Deliverable D2.1

Markets for DSO and TSO procurement of innovative grid services: Specification of the architecture, operation and clearing algorithms

V1.0

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Executive summary

This deliverable reports on CoordiNet D2.1 "Markets for DSO and TSO procurement of innovative grid services: Specification of the architecture, operation and clearing algorithms" which describes the main characteristics of the market design dimensions and principles, but also how those principles are used in practice for the different CoordiNet demonstration campaigns. A special emphasis is given on congestion management, baseline methodology and market-clearing functionalities, tools and requirements for each demonstrator in the project. This deliverable coordinates the procurement schemes for different products, considering the nature of the product and including the specification of technical requirements, the existing market platforms and regulatory framework. The overall system architecture is defined for the different demonstration campaigns and, hence, this deliverable is linked with the different specifications as reported in the documentation for the demonstration campaigns in Spain [1], Sweden [2] and Greece [3][4], respectively.

Market design is a broad topic, so before going into the CoordiNet demonstration campaigns in detail, this document contains definitions of energy market terminology to avoid any ambiguity. The focus is on energy market services, coordination schemes, market products, and the main dimensions that need to be taken into account in a market design.

Using proper market design definitions allows for describing the relevant aspects of the market implemented in the three CoordiNet demonstrators. First, a general description of every demonstration design is provided.

This document presents how the markets are currently organized in each demo country and how the markets implemented in CoordiNet are integrated into existing frameworks. The balancing responsibility allocation for demand, generation, storage, and aggregation are also detailed case by case.

This document also focuses on the link between market design and congestion management. First, standard identity cards (i.e. comparative tables) are listed to summarize the situations for each demonstration campaign. Then, more in-depth analyses are conducted to study the implication of the coordination scheme and market design on the efficient procurement of congestion management services.

Another point of focus related to congestion management is about the baseline methodology and its application in the CoordiNet project. This document studies the most suitable baseline methodologies for providing congestion management for the three demonstrators' countries of the project.

Finally, the document identifies market tools and their associated functionalities and requirements that are required to address the objective of the business use cases regarding market management.

The outcome of this document is a better understanding of market design for each demo using appropriate and well-defined terms. Using rigours definitions, a description of how the congestion management process is integrated into the existing framework was produced. Moreover, in this area, some small attention points are raised, such as transparency improvement, liquidity problem and gaming opportunity. Regarding the baseline, some specific recommendations are made for each demo based on the analysis conducted in this document.

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1. Notations, abbreviations and acronyms

Acronym	Description
AC	Alternating Current
ACL	Average Coincident Load
ATC	Available Transmission Capacity
aFRR	Automatic Frequency Restoration Reserve
AMI	Advanced Metering Infrastructure
AS	Ancillary Services
BRP	Balancing Responsible Party
BSP	Balancing Service Provider
BUC	Business Use Case
CAISO	California Independent System Operator
CBL	Customer Baseline Load
CSP	Curtailment Service Provider
DA	Day-ahead
DC	Direct Current
DER	Distributed Energy Resources
DR	Demand Response
DRM	Demand Response Mechanism
DRP	Demand Response Participant
DSO	Distribution System Operator
ELRP	Emergency Load Response Program
ERCOT	Electric Reliability Council of Texas
ERS	Emergency Response Service
FB	Flow-based
FCR	Frequency Containment Reserve
FSP	Flexibility Service Provider
GCT	Gate Closure Time
GOPACS	Grid Operators Platform for Congestion Solutions
HETS	Hellenic Electricity Transmission System
HV	High Voltage
HVDC	High Voltage Direct Current
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
ISP	Imbalance Settlement Period
kW	Kilowatt
LV	Low Voltage
MBMA	Meter Before / Meter After
MBL	Maximum Base Load
mFRR	Manual Frequency Restoration Reserve
mFRRda	Manual Frequency Restoration Reserve directly activated

MGO	Metering Generator Output
MISO	Midwest Independent System Operator
MV	Medium Voltage
MW	Megawatt
NAESB	North American Energy Standards Board
NYISO	New York Independent System Operator
PJM	Pennsylvania, New Jersey, and Maryland RTO
PLC	Peak Load Contribution
PTDF	Power Transfer Distribution Factors
RES	Renewable Energy Source
RLC	Remaining Line Capacities
RO	Regulation Object
ROD	Reserve Power Other Purposes
RR	Replacement Reserves
RTO	Regional Transmission Organization
SO	System Operator
SOCP	Second Order Cone Programming
ToE	Transfer of Energy
TSO	Transmission System Operator
US	United States

Table 1: Acronyms list

2. Introduction

2.1. The CoordiNet project

The CoordiNet project is a response to the call LC-SC3-ES-5-2018-2020, entitled "TSO – DSO – Consumer: Large-scale demonstrations of innovative grid services through demand response, storage and small-scale generation" of the Horizon 2020 programme. The project aims at demonstrating how Distribution System Operators (DSO) and Transmission System Operators (TSO) shall act in a coordinated manner to procure and activate system services in the most reliable and efficient way through the implementation of three large-scale demonstrations. The CoordiNet project is centered on three key objectives:

1. To demonstrate to which extent coordination between TSO/DSO will lead to a cheaper, more reliable and more environmentally friendly electricity supply to the consumers through the implementation of three demonstrations at large scale, in cooperation with market participants.
2. To define and test a set of standardised products and the related key parameters for system services, including the reservation and activation process for the use of the assets and finally the settlement process.
3. To specify and develop a TSO-DSO-Consumers cooperation platform starting with the necessary building blocks for the demonstration sites. These components will pave the way for the interoperable development of a pan-European market that will allow all market participants to provide energy services and opens up new revenue streams for consumers providing system services.

In total, ten demonstration activities will be carried out in three different countries, namely Spain, Sweden and Greece. In each demonstration activity, different products will be tested, in different time frames and relying on the provision of flexibility by different types of Distributed Energy Resources (DER). Figure 1 presents an approach to identify (standardized) products, system services, and coordination schemes to incorporate them into the future CoordiNet platform for the realization of the planned demonstration activities. More details about the process to define the Business Use Cases (BUCs) can be found in D1.5 [52].

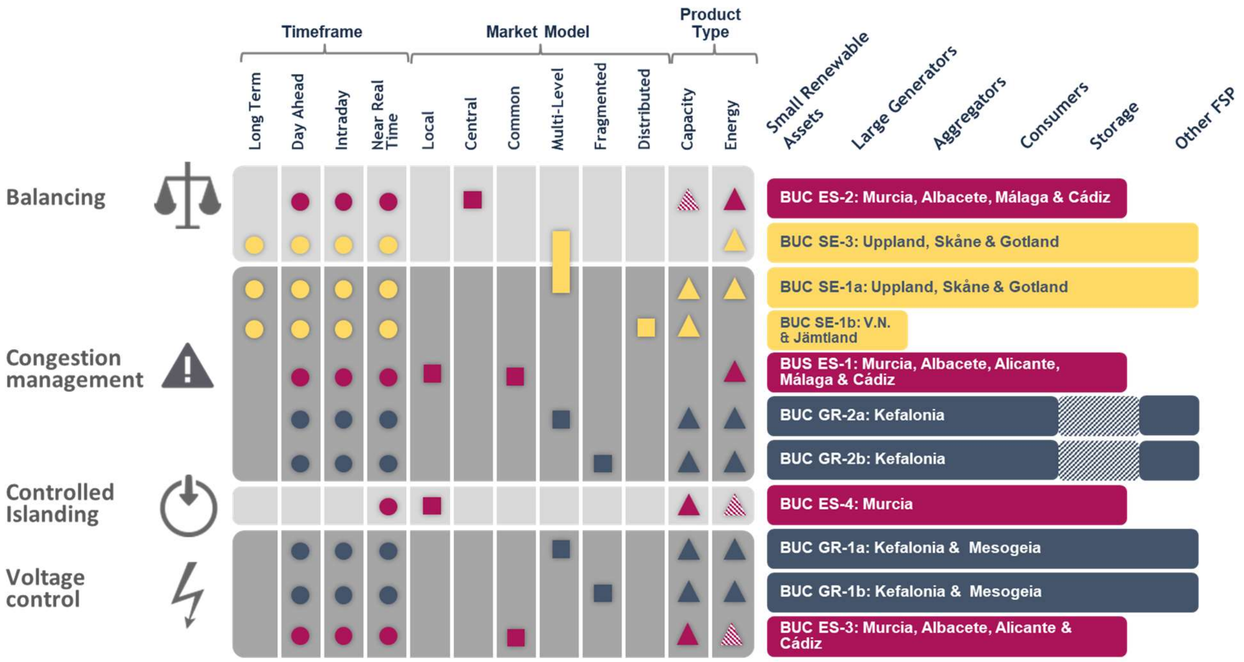

Figure 1: Overall CoordiNet approach: Services, timeframes, coordination schemes and products that will be demonstrated in different countries (Spain in pink, Sweden in yellow, and Greece in grey)

2.2. Scope of the document

To achieve the key objectives, the project work is articulated in 9 Work Packages (WP), including the 3 demonstrations. Interdependences and cross WP workflow, as well as the interactions among WP2 tasks are illustrated in Figure 2, highlighting the input/output relations between the project activities necessary to meet the objectives.

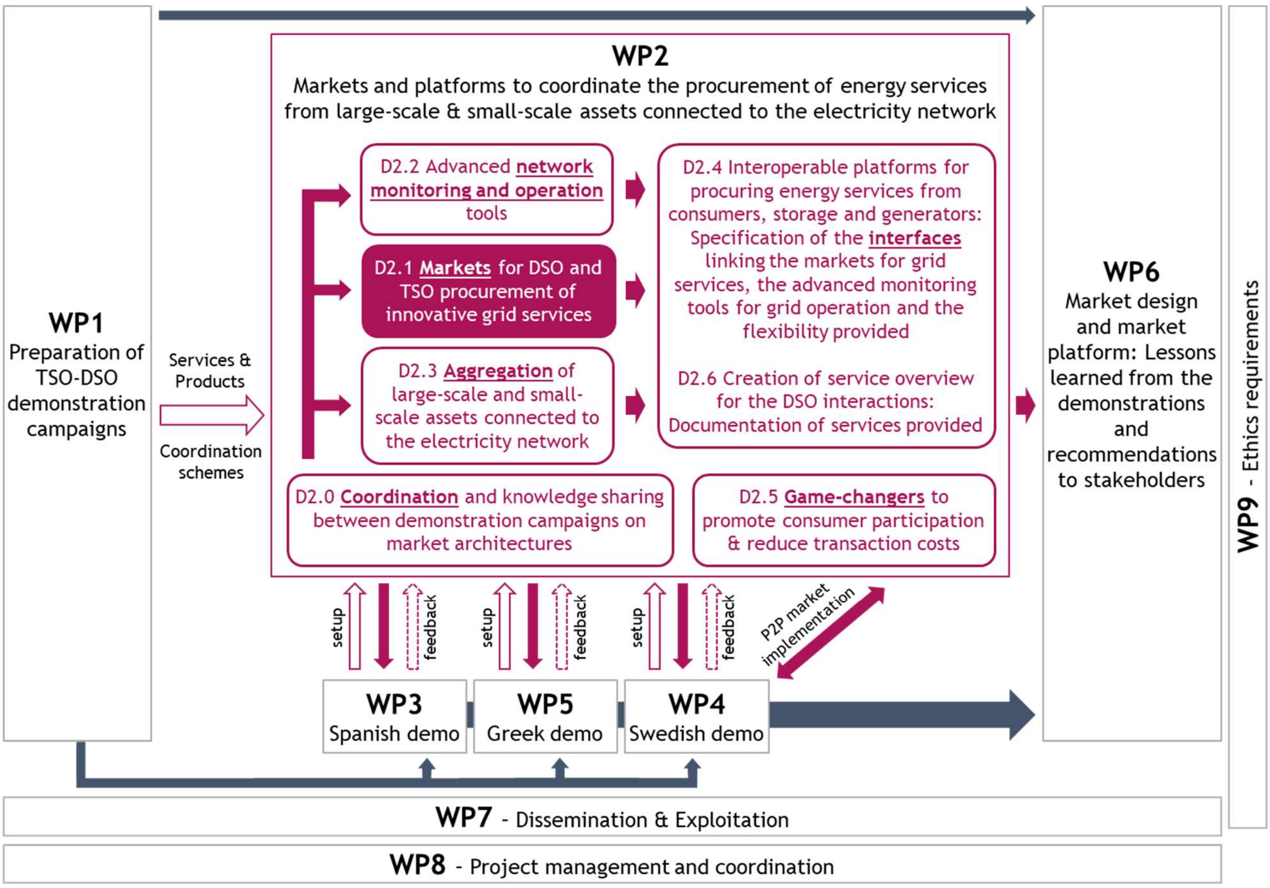

Figure 2: Main interactions and links of WP2 deliverables with the other WPs of the CoordiNet project

This deliverable reports on CoordiNet task 2.1 “Markets for DSO and TSO procurement of innovative grid services: Specification of the architecture, operation and clearing algorithms” which describes the main characteristics of the market design dimensions and is organized in the following six chapters.

- The second chapter is dedicated to general definitions related to market design. This contains a list and details of the more common market dimension.
- The third chapter is focused on the explicit market design on the tree demo countries: Spain, Sweden and Greece.
- Chapter four describes how the market design is used for solving congestion management and the fifth chapter is dedicated to the detailed analysis of the different congestion management cases.
- Chapter six discusses the different usage of baseline methodology for congestion management and the implication for the CoordiNet demonstration campaigns.
- Chapter seven lists the different market-clearing functionalities, tools and requirements used in the different demonstration campaigns.

3. Market Applications, Terms and Dimensions

3.1. Introduction

This chapter defines energy market terminology and dimensions along which the different market tools implemented by the CoordiNet demonstration campaigns can be mapped and with which a more "ideal" market design can be established.

Here, dimensions are defined as the main axes according to which a single (or sometimes multiple) choice should be made when implementing a market. Indeed, depending on the use case or the purpose, several questions will come up and decisions will need to be made: e.g. how to define the pricing rule? Should it be pay-as-bid or pay-as-cleared? Defining these dimensions and choices allows to put in place the common framework based on which market design can be debated and best configurations can be established.

The goal of this chapter is to settle the framework based on which the investigations of task 2.2 have been be conducted. Indeed, the description of these market dimensions introduces the concepts enabling the proper mapping between (a) what is implemented in each BUC of each demo and (b) what would be the future "ideal" European coordination platform design, which will be further investigated in this deliverable.

This document is aimed to be self-contained, with the exception of referring to the WP2 glossary that defines electricity system terms, but not electricity market terms.

3.2. Definition of Terms

For "energy system terms" we refer to the WP2 Glossary rather than repeating these definitions here. The definition of basic "energy **market** terms" is given in the following paragraphs. These terms are needed to understand the rest of this document. For more details related to the following definition, see [5].

Injection vs. Offtake: Injection is the term for delivering energy/power to a node (bus) of the electricity network. Offtake is the term for extracting energy/power from a node of the network. For example, generators/electricity producers will inject power into the network, while load/consumers will offtake power from the network.

Supply vs. Demand: The *supply side* of the market corresponds to the stakeholders offering the commodity in the market, while the *demand side* of the market corresponds to the stakeholders requesting the commodity in the market. Both sides are *matched* by the market, resulting in the same total quantity in MW(h) being accepted on the supply as the demand side, minus the losses. For example, in the day-ahead spot market, the supply side would refer to the electricity producers or generators offering energy in the market (injection), while the demand side would refer to the energy consumers or load (offtake). In a balancing market, the supply side would correspond to the balancing service providers (BSPs) offering their flexibility (which can be upward or downward, which means an injection of energy or an offtake of energy), while the demand side would correspond to the TSO buying flexibility services.

Market Participant: A natural or legal person who buys, sells or generates electricity, who is engaged in aggregation or who is an operator of demand response or energy storage services, including through the placing of orders to trade, in one or more electricity markets, including in balancing energy markets. [6]

Market Horizon: A market can aim to optimize its outcome for a single time step. Some markets aim to optimize their outcome over a period containing multiple time steps. The period over which a market optimizes is called the *market horizon*. Sometimes there are temporal constraints in the modelled network (e.g. line ramp constraints) or presented market bids (e.g. device ramp constraints or minimal up/down times). For these entities to be able to participate in the market, it is then needed or more realistic to have multiple time steps present in the market horizon rather than only the first one into the future. As such, the temporal constraints can be taken into account, for longer in advance than is the case with a market with a single time step horizon.

Market Timing: Some timing aspects must be considered [7]:

- *Market horizon*/Optimization period/Delivery window: Time period considered for the market clearing (e.g. 24 hours on the day-ahead market).
- *Time granularity*/time step: Time granularity for the market clearing (e.g. 1 hour on the day-ahead market). The time granularity can be lower or equal to the time horizon. Typically, the time horizon is split into one or several time steps.
- *Gate closure time*: Time at which orders from market participants can no longer be changed and no new orders can be accepted.
- *Clearing frequency*: It defines how often the market is cleared (e.g. every day for the day-ahead market).
- *Max market clearing duration* (also called maximum activation optimization function): maximum time allowed to the market clearing to find a(n) (optimal) solution.

Losses: Difference between all the energy that is injected into a system (which includes not only generation but, in some cases, also imported energy) and the billed energy consumed (energy going out of a system would also include exports in some cases). Power losses are an inherent part of electrical grids (e.g. resistance, theft, miscalculations, …). They are a consequence of transmission and distribution of electrical energy and will always be part of any traditional electrical system. There is a lack of harmonised definitions and rules of power losses across Europe [8].

Frequency control: Capability of a power-generating module or HVDC system to adjust its active power output in response to a measured deviation of system frequency from a setpoint, in order to maintain stable system frequency [9]. In addition, load shedding can also be used for frequency control.

Balancing: All actions and processes, in all timelines, through which TSOs ensure, in an ongoing manner, maintenance of the system frequency within a predefined stability range and compliance with the amount of reserves needed with respect to the required quality [6].

Voltage control: Manual or automatic control actions at the generation node, at the end nodes of the AC lines or HVDC systems, on transformers, or other means, designed to maintain the set voltage level or the set value of reactive power [10].

Congestion management: Set of actions that the network operator performs to avoid or relieve a deviation of the electrical parameters from the limits that define the secure operation. This term includes congestion management and voltage control [11].

Island operation: The independent operation of a whole network or part of a network that is isolated after being disconnected from the interconnected system, having at least one power generating module or HVDC system supplying power to this network and controlling the frequency and voltage [9].

Granularity: The smallest increment in volume of a bid [12].

3.3. Typical Energy Market Services / Applications

The term “market applications” is here defined as the purpose for which the market is used or, in other words, the service that the market is offering. Note that a “market application” cannot be considered in itself as a “market dimension”. Indeed, the same “market design” could be used for multiple applications, while a given market design could not be at the same time e.g. “pay-as-bid” and “pay-as-cleared”. Therefore, the “market application” is not considered as a dimension, even though it will of course drive the market design choices to be made. As it is not in itself a “market dimension”, it is presented separately in this section, while the market dimensions are introduced in next sections.

In CoordiNet, the markets are offering system services, which are defined as “services provided to DSOs and TSOs to keep the operation of the grid within acceptable limits for security of supply and are delivered mainly by third parties” (based on [11] (CEDEC et al., 2019)). The particular application considered in the CoordiNet Project are (1) balancing, (2) congestion management, (3) voltage control and (4) controlled islanding. In order to make this deliverable self-supportive, we provide in what follows a brief reminder of these services but we refer the reader to the paper from K. Kessels *et al*. [12] for an extensive description of these services.

3.3.1. Frequency Control (Containment and Recovery), Balancing

To keep AC electricity networks in synchronization, they have to run at the same frequency (within a small tolerance). This frequency depends on the imbalance between generation and consumption. With more generation than consumption, the frequency will increase. With more consumption than generation, the frequency will decrease. So good balancing of generation and consumption will achieve a stable frequency. This is called *frequency control*.

There can be two steps in frequency control: frequency containment and frequency recovery. *Frequency containment* will try to keep the frequency in a certain band around the 50 or 60Hz defined as the target, so to contain the problem of deviation from the target frequency, but not to totally solve the problem. *Frequency recovery* will try to get the frequency back to the target frequency.

Due to imperfect forecasts, or unforeseen generation outages, methods for keeping the balance when the frequency is too low always rely on (1) activating reserved generation for which contracts were setup before or/and (2) load shedding if a consumer contract allows this. When the frequency is too high, balancing relies on (1) reducing generation or/and (2) increasing consumption.

For balancing, the containment and recovery parts are often separated in different categories: Frequency Containment Reserve (FCR), Frequency Restoration Reserve (automatic (aFRR) and manual (mFRR)) and Replacement Reserve (RR).

The nature and goals of FCR, FRR, and RR are briefly defined next (see [13] for more details):

- Frequency Containment Reserve - FCR: The goal of FCR (which is also known as the “primary reserve”) is to stabilize the frequency (within seconds) in the synchronous system by restoring/ensuring the balance between the supplied and demanded power (the stabilized frequency might still be different than the nominal frequency).

- Frequency Restoration Reserve – FRR: In contrast with the FCR, the goal of FRR (which is also known as the "secondary reserve") is to restore the frequency to its nominal value within a certain synchronous zone (activated within seconds and up to several minutes, e.g. 30 seconds to 15 minutes). The aFRR is activated automatically (e.g. within 30 seconds) and mainly targets short term imbalances, while mFRR is activated manually and mainly targets longer term imbalances.
- Replacement Reserve – RR: RR (which is also known as the "tertiary reserve"[1]) is used in case of major imbalances, that may not be balanced using FRR, and is active in the range of minutes to hours. The activation of RR, which may use additional generation or interruptible demand, also frees-up FRR units to be (re-)used for frequency restoration in the case of short-term imbalances.

The essential part of a market model providing balancing is that it has a *power balance equation* that equates the sum of injected power (at all injection nodes) and imported power to the sum of withdrawn power (at all offtake nodes), exported power, and power losses over network edges (lines). This is usually managed by TSOs. An optimization model containing this equation, should define enough variables (flexibilities) in (1) its injection and offtake bids or/and (2) its import and export flows to make this equation hold.

3.3.2. Voltage Control

Devices attached to an electricity network will not operate properly if the voltage of their network node they are connected to is not within the device specifications. When the voltage is too low, they may not operate at all. When the voltage is too high, they may get damaged.

For this reason, voltage at the network nodes should be stable around the specified target value, only allowing some small tolerance. Methods to realize this fall under the name of *voltage control*. Since the voltage depends on the presence of reactive energy in the system, controlling reactive energy is the major way to steer a voltage in the desired direction.

- To lower the voltage the reactive power should be lowered, which involves increasing inductive elements.
- To increase the voltage, reactive power should be increased, which involves increasing capacitive elements).

Separating voltage control methods into containment and recovery methods is less often done than in balancing.

A market model that provides voltage control typically has a lower and upper bound on the voltage allowed (e.g. EN 50160 standard) for all nodes in the network. For an optimization model to achieve this *voltage containment* in all nodes, it needs to be able to use enough variables (flexibilities) in terms of capacitive and inductive elements to steer reactive energy and with that the voltage for all the nodes in the right direction. This is usually managed by DSOs.

[1] Although some countries, e.g. Spain, call tertiary reserve to mFRR.

3.3.3. Congestion Management

In the context of electricity networks, congestion is the term used for when the energy flow on a network reaches this maximum that an electricity line can support. When this happens, we say the line capacity limit *constraint is tight*. In this case it incurs an additional cost towards the node the energy flows to. This cost is called the *congestion rent* or *congestion cost*. In mathematical terms it corresponds to the *shadow price* of the line capacity constraint.

The idea of *congestion management* is to avoid exceeding lines capacities, so a network model aiming at that will have constraints limiting the power flows to a maximum value that can be supported by the line. It will not avoid that some lines are being used at full capacity, so it will not avoid congestion cost being non-zero.

Note that in practice, we can distinguish between physical congestion, market congestion and structural congestion. For more details, see the following TSO-DSO report [14].

An optimization model that includes congestion management, will try to exploit the variability (flexibility) present in injection and offtake market bids as well as any flexibility in the import or export contracts.

3.3.4. Controlled Islanding

Controlled islanding is the term for the management of a zone of an electricity network that is or gets disconnected from the rest of an electricity network. One use case is the study on what happens when an electricity zone is connected by just one or a few cables to the rest of the network and these cables would suddenly be damaged or become unavailable. Another use case is when part of the grid is disconnected from the rest of the system due to scheduled maintenance actions.

The island zone needs to *manage its own balance* and also do *voltage control management and potentially congestion management*. There is not import nor export, so the only variability an optimization model can rely on is the flexibility in the injection and offtake market bids.

3.4. Coordination Schemes

In the context of CoordiNet, Coordination Schemes are agreements defining the roles, responsibilities, and exchange of information between the different parties involved in the procurement and activation of a service at the transmission or distribution sides. These parties can be TSOs, DSOs and FSPs and possibly also BSPs and BRPs. We refer to CoordiNet D1.3 [12] for a detailed description and analysis of the coordination schemes defined in the CoordiNet project.

The relation of coordination schemes with markets is that some coordination schemes may define more decentralized markets than others, which implies that in the former smaller markets have to be cleared, either in parallel or sequentially. Sometimes, bids may be cleared multiple times when they are cleared in a first market and then sent on to a second market.

3.5. Market Products

The market product is in essence the type of commodity that is exchanged on the market. The main products we are interested in for the energy markets are: (1) reserve (capacity), (2) energy and (3) reactive power.

Bids can be offered in MW for a reserve market and in MWh for an energy market. Reactive power is typically modeled when voltage is to be known and controlled, so in that sense the market products axis is not entirely orthogonal to the market services axis.

Of course, a market can trade different products, one well-known example are the markets performing a co-optimization of reserve and energy, such as in Greece or in the United States.

3.6. Definition of Market Dimensions

This section describes the "market dimensions" mentioned previously. These dimensions are the main choices that are at stake when designing a market. For this specific project, the following market dimensions have been considered: (1) trading type, (2) auction type, (3) centralization level, (4) market pricing scheme, (5) bid types, (6) objective type and (7) network representation in the market. The goal here is to give a general overview of the market definitions in general and, in the next chapters, those concepts will be mapped to each demonstration campaign.

3.6.1. Trading Type

3.6.1.1. Unit-Based Trading vs. Portfolio-Based Trading

In an energy market context, a *unit* most commonly has the meaning of a large physical unit of generation, like a gas turbine, nuclear power plant or virtual power plant (i.e. aggregation of units together with demand side assets). It can also mean a unit of consumption. A *portfolio* represents a collection of such units. The portfolio owner that will bid this collection into the market is not necessarily the owner of the units, but he can be.

As for the market, **unit bidding** means that the market bids are formulated as one bid per unit, whereas for **portfolio bidding**, a bid will correspond to an aggregation of units. Unit bidding is, for example, very popular in the US, where some markets are modelled as a "unit commitment" which mathematically models the physical constraints of the assets (e.g. ramping constraints or start-up costs). Portfolio bidding is popular in EU, for instance it is used in the day-ahead EU spot market, where the bidders have access to various types of "bids" (such as block bids, single bids…) which have a more indirect link to the physical constraints of the assets. While a unit bid tries to recover the associated running costs plus make some profit, portfolio bidding combines a collection of bids that of course aims for profit but can also have the intention of minimizing risk by hedging.

In the scope of CoordiNet, the markets follow a portfolio bidding setup. This also triggers an interesting question studied in the project, which is related to the aggregation work performed by the aggregator which has to develop a bidding strategy to smartly combine his assets into market bids (see Deliverable 2.3 [15]).

3.6.1.2. Bilateral Trading vs. Multilateral Trading

Bilateral trading is to be contrasted with multilateral trading. The former means that only two participants take part in 'the market', where indeed it can be questioned if such a market really has the properties of low entry barriers, high transparency, liquidity and competition and efficiency usually associated to it. These properties would be more apparent when there are many participants on both supply and demand sides, so in a multi-lateral market.

3.6.1.3. Asymmetric vs. Symmetric Market

An example of an asymmetric market would be one where, first, all sellers of flexibility would submit their bids and, after that, a single, or more buyers would be able to pick the bids and decide the activation level they like for them. The intermediate system between supply and demand, then, has no complex clearing algorithm to run, but rather plays the role of bookkeeping the bids. It could possibly do some checking of physical constraints or still run an entire power flow model which would then prevent the demand side to activate too much injection for example. The other example of an asymmetric market would be that demand submits all bids first and supply can pick and choose activation levels for the bids second.

3.6.2. Auction Type

3.6.2.1. Closed-gate Auction versus Continuous market.

A **closed-gate auction** is an auction or market where all the bids, whether supply or demand, need to be received before a deadline, called *gate closure time*. This deadline is known to the bidders. This means that there will be a time during which bids are collected up to the deadline and that bids submitted after the deadline are rejected. Shortly after the deadline, market clearing will start, taking into account only the timely submitted bids and this in a fashion typically independent of their submission time.

Typically, in energy markets, a closed-gate auction implies that there is also a periodic repetition of the gate closures deadlines. For example, naturally, the ‘day-ahead electricity market’ has a daily deadline.

In **continuous markets**, there is no separation into a bid collection and bid processing phase. Rather, bids are processed by a market as soon as they are received by the market. So here the treatment of bids typically depends on the precise time of submission.

3.6.2.2. Independent Horizons vs. Rolling Horizon.

When a market is repeated in a periodic way, the markets horizons of two subsequent market clearings can either be *disjunct* (independent) or be *overlapping* (rolling). In the former case, the horizons are *independent*, which means that any given time step only occurs in the horizon of a single market. This implies that when the market decides on that timestep (what bids to accept to what extent), that this decision will be *final*, since it will never be reconsidered by a subsequent market. When, on the contrary, two subsequent markets have overlapping horizons, decisions made by the first market, for a time step in this overlapping time, are to be considered only as *advisory*, since they will be reconsidered by the second market.

Constructing, as well as processing bid acceptance answers from a rolling horizon is of course more complex than the same for a market sequence with non-overlapping time horizons.

3.6.3. Centralization level

Centralization level refers to the fact that the market is organized around a central actor or not. Even though the term *market* means to bring together bidding parties to one place, decentralized markets still exist and to some extent gain in popularity, one example being *peer-to-peer energy markets*. Decentralisation, then, refers to replacing a global central market with multiple, more locally bound, independently working, sub-markets. The drive for this can be deregulation, disintermediation or/and the availability of new more local, often more renewable and sometimes cheaper sources of energy. So, the drive for decentralization comes from properties outside pure market economics, since, oppositely, market efficiency is generally lower when markets are more decoupled, decentralized or fragmented.

The seven Coordination schemes as defined in [12] each show varying degrees of centralization/decentralization.

3.6.4. Market Pricing Method Type

3.6.4.1. Uniform Pricing vs. Non-Uniform Pricing

The **uniform pricing** scheme refers to a setup where a commodity is sold at the same price for all the sellers/buyers. In the context of an electricity market, it means that a MW for a certain period *t* and a certain location *n* will be paid at the same price for all the producers. A **non-uniform price** scheme, on the opposite, refers to a setup where all the sellers and buyers does not receive/pay the same price for the same commodity.

Let's consider the following example to illustrate the concept (Figure 3: Uniform pricing example). On the left, three fully *divisible* supply bids, two of 5 MW and one of 3 MW, rank from 10 to 25 €/MWh. There is an inelastic demand of 8 MW. On the right, the same configuration, except that the second supply bid of 5 MW is a fully *indivisible* block bid.

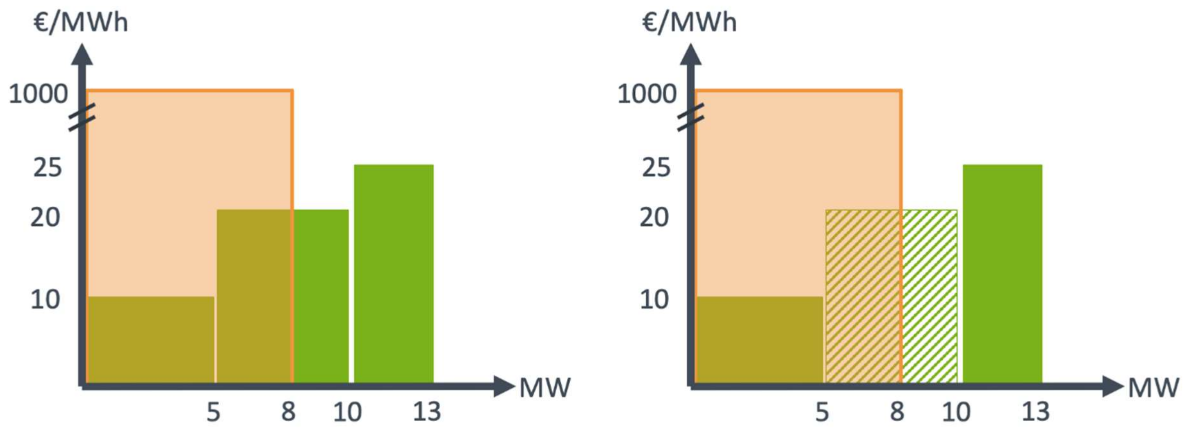

Figure 3: Uniform pricing example

An example of uniform pricing is the "pay as cleared pricing". We call a market **Pay as Cleared** when the bidders - in the same bidding area - are all paid the cleared price of that area. So this means that they all receive the same amount of euros per MW(h), or the same financial volume in any other agreed currency. So, their reward is independent of their respective bidding prices. Of course, it does not mean that all bids are accepted. Bids with a higher bidding price than this cleared price are rejected. Pay as clear has interesting economical properties, for instance, this approach removes/reduces the risk of a market participant bidding in terms of what they want to receive instead of in terms of their real cost of flexibility. In the example of the left above, in a pay-as-cleared setup, the clearing price will be 20€/MWh. The first supply bid will be accepted completely (5 MW) and cleared at 20€/MWh. The second bid is cleared up to 3 MW and also receives 20€/MWh.

Nevertheless, let's notice that finding an "equilibrium price", meaning a price which on its own provides the right incentives to all the market participants to follow their dispatch cleared by the market, is not always possible. Mathematically, when the problem is non-convex (e.g. when the market includes block bids or more generally market orders which includes a binary decision), strong duality does not hold which means the primal problem (which computes the dispatch) and dual problem (which computes the prices) may not have an identical solution. This can be illustrated with the above right example: the second bid cannot be cleared as it is a block bid and that demand is only of 8 MW. Therefore, the solution consists of clearing the first and last supply bid, which lead to a clearing price of 25 €/MWh. At this clearing price, the second supply bid would have liked to produce as it would have been profitable. This has been called in the literature a “paradoxically rejected block” as it is a block rejected despite it is profitable. In this case, the second supply bid would have an incentive from the clearing price to deviate from its dispatch, which is why the price cannot be considered as an equilibrium price.

On the contrary, an example of non-uniform pricing is pay as bid. A **pay-as-bid** scheme means that the accepted bids, to the level they were accepted, are paid with a reward per MW(h) that is equal to their bid price. This means that in a single bidding area, bidders can get different rewards. However, it does not give incentive for the market participants to bid their real cost of flexibility, potentially introducing an economic distortion in the merit order and thus, creating the possibility that cost-efficient bids are not activated. [7]. In the above left example, a pay-as-bid setup would mean that the first bid is paid 10€/MWh for the 5 MW sold while the second bid is paid 20€/MWh for the cleared quantity of 3 MW.

More complex non-uniform pricing also exists and are relevant in various situations. For example, in the situation mentioned above where an equilibrium price cannot be found, one way to make “pay-as-cleared” applicable is to complement it with **side payments**. This is a non-uniform pricing scheme as the market participants are not paid at the same price: they all receive a uniform pricing corresponding to the market price and their cleared quantities, but on top of this, some market participants receive side payments. The side payments are basically used to restore the right incentives for all the bidders, e.g.: a cleared bid that is out-of-the-money with respect to the clearing price can be compensated for its losses with side payments; similarly, a non-cleared bid which is in-the-money with respect to the clearing price can be compensated for its opportunity costs with side payments. One example of these non-uniform pricing schemes using side payments is the so-called “Convex Hull Pricing”.

3.6.4.2. Nodal vs. Zonal Pricing

Consider that when a market is defined over a domain with multiple locations, so multiple nodes, the cleared price for any two nodes could differ. If the technique used can produce such differences, we call it a **nodal pricing** technique. Reasons for different cleared prices between a couple of nodes are losses or congestion on lines between those nodes, or also that there is no physical direct or indirect connection at all between two nodes. When a line from node A to node B has a non-zero resistance (in the market network model) a non-zero loss will occur from A to B, leading to a higher price per Watt in B than in A. Also, when congestion occurs on the line from A to B, meaning that it is used at full capacity, the price in B will be higher than in A. So, generally, we get that energy only flow towards locations with a higher price. (Some exceptions to this rule exist, which are called *non-intuitive flows*.)

A zone is a collection of nodes. The term **zonal pricing** is used to mean that the market rules are such that the cleared price for all nodes in a zone are the same. Note that this requirement can sometimes be imposed on the demand bids only or on the supply bids only, or on both at the same time and in addition also that supply and demand cleared prices should be the same for that zone. An example of zonal pricing is the Prezzo Unico Nazionale (PUN) in the Italian day ahead market, where it is required that the cleared price, for the demand bids only, is the same for all nodes per zone for all day-ahead zones defined in Italy.

Zonal instead of nodal pricing typically requires adding some extra constraints in the market model, which typically increase model solving algorithm complexity and model solving time. On the other hand, nodal pricing typically includes line capacity constraints over every line in the network, which may increase the underlying market clearing complexity and the complexity of determining the optimal dispatch, and, therefore, the solving time.

When network constraints are considered, pay as clear can be adapted to a system with network constraints in different ways [7]:

- Nodal approach: A price for flexibility is associated to the most granular level in the network representation, i. e. to each node of the modelled grid.
- Zonal approach: A price for flexibility is associated to a zone covering different nodes. Each zone can have a different price but the nodes in the same zone have the same price.

3.6.5. Bid Types

In portfolio-based trading, which is the most used setup in CoordiNet, the products which are sold on the market are financial products called “orders” or “bids”. Different types of bids are used in the markets:

There are three main levels of complexity in bids, three “dimensions” or “degrees of freedom” which are (1) the **quantity** offered by the bid, (2) the **price** at which the quantity is offered and (3) the **time** periods for which the quantity is sold. In Figure 4: Abstract bid structure, the two front bids are offered both for period t=1 and differs from the quantity and price they offer. The first bid behind spanned over three time periods (t=2, 3 and 4).

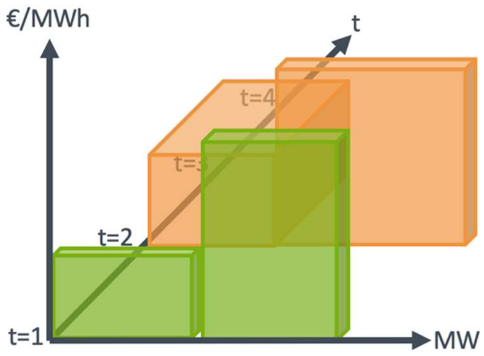

Figure 4: Abstract bid structure

On top of these three main fundamental degrees of freedom, some additional constraints can be defined on the bids such as interdependence of the bids.

3.6.5.1. Single Quantity Bid

The simplest type of bid is one where a single quantity (in MW(h)) is specified and a single price in EUR/MW (for the duration of the reserved capacity) or in EUR/MWh for the energy. This bid is supposed to be offered to the market as a supply or demand bid, for a single time step and for a single bidding area.

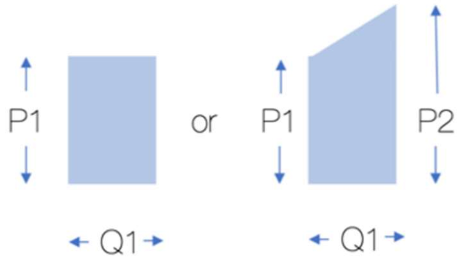

Figure 5: Elementary bid with one quantity and one price or one quantity and two prices

As indicated in Figure 5, this bid can be represented by a rectangular shape of which the quantity (Q in MW(h)) is the width and the price (P1 (in EUR/MW)) is the height. When a – unitless - fraction x (0.0 <= x <= 1.0) of the quantity is cleared, x * Q in (MW(h)) is accepted. In a pay-as-bid payment scheme x * Q * P1 (in EUR) would be paid out by the market operator to the bidder, if it would be a supply bid. x * Q * P1 would be paid to the market operator if it would be a demand bid. When only such rectangular shaped bids are present in the market, and the objective is social welfare, this objective is linear in the x variables.

A variant on this most simple bid is one where two prices are specified: P1 and P2. When a larger fraction x of this bid is accepted, the price in EUR/MW(h) increases. When such bids are present in the market, and the objective is social welfare, the objective becomes quadratic in x instead of linear.

3.6.5.2. Multi-Quantity Bid

It is possible that a bidder cannot accurately describe that he wants to be paid more per MW(h) unit when the market accepts more of his bid, so when the x fraction increases. On the demand side, a bidder will be wanting to pay less for buying increasing MW(h) units. To accommodate this, a sequence of subsequent single quantity bids can be juxtaposed on the quantity axis, each having its own price. For a multi-quantity supply bid, this is illustrated in Figure 6 below.

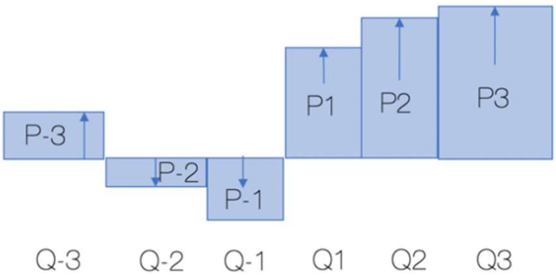

Figure 6: Multi-quantity bid for a single time step

Along the positive quantity axis towards the right, prices are non-decreasing. Along the negative quantity axis, prices towards the left, prices are non-decreasing too. One can bid a multi-quantity bid with only positive or only negative or both negative and positive quantities Q_i.

In fact, offering the collection of the multi-quantity bid as one composed bid or offering the composing bids separate to the market makes no difference. However, a collection at this level is defined, so that both a composed scalar and a Boolean acceptance variable over it can be defined (when needed), which can then be directly used at the next higher level bid it is part of, or used in constraints over it.

3.6.5.3. Multi-Quantity, Multi-Time Step or Block Bids

This next higher-level bid is the multi-quantity-multi-time step bid. It collects a series of multi-quantity bids, juxtaposed in subsequent time steps. This is illustrated in Figure 7 below.

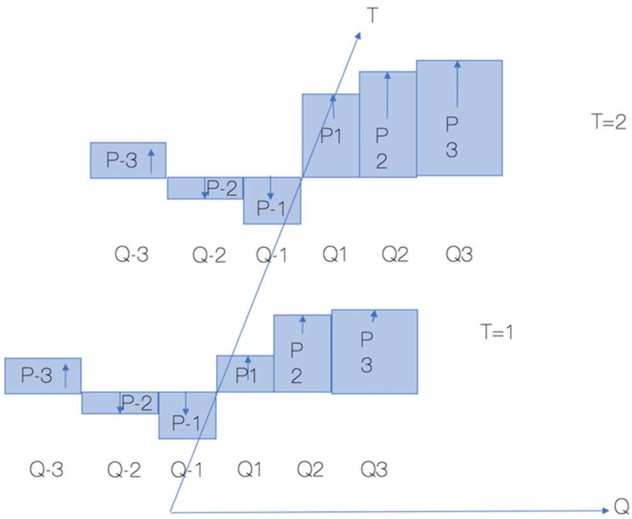

Figure 7: Multi quantity bids across multiple time steps

Two similar supply multi-quantity bids can be noticed, the first one defined on time step T=1, and the second on time step T=2. In the context of the electricity markets, this type of bid is called “block bid” and comes with an additional constraint, which is a Boolean acceptance variable: the bid is fully accepted or fully rejected.

3.6.6. Constraint Types

A large series of possible constraints can be defined. A non-exhaustive list of constraints which are the most popular ones is presented next.

3.6.6.1. Ramping Constraint

A ramping constraint limits the delta acceptance in MW(h), by imposing a lower and/or upper bound, from a time step to the next. Thus, it is a temporal constraint. It is most easily definable on a multi-time step (multi-quantity) bid.

The load gradient enables the maximum difference between the energy in one hour and the energy in the following hour of the production unit to be established, limiting maximum matchable energy by matching the previous hour and the following hour, in order to avoid sudden changes in the production units that the latter are unable to follow from a technical standpoint [16].

3.6.6.2. Integral Constraint

An integral constraint limits the total, accumulated, from the first to the last time step, (integral) acceptance in MW(h), over a multi-time step (multi-quantity) bid. Thus, it is a temporal constraint.

3.6.6.3. Cumulative Constraint

A cumulative constraint requires that, for both bids in a bid couple, their acceptance variables ‘x’, sum up to at most 1 (100%). This can be needed, for example, for supply bids, to be able to model that two processes are alternatives capable to deliver the same output, but that they are constrained together because they physically use an input with a fixed upper-bound. Another option to model this would just be to add the quantities for these processes into a single bid per multi-time-step bid. However, this may not be possible if different further constraints are needed per separate multi-time-step bid to model the two different processes.

3.6.6.4. Implication Constraint

An implication constraint is a constraint between two bids (at whatever of the three bid levels defined above) that enforces that, when the first bid is accepted (at any non-zero acceptance level), the second should also be accepted (at any non-zero level).

3.6.6.5. Link Constraint

A link constraint is a constraint between two bids that requires the first bid to be accepted before the second can be accepted. This is also referred in the literature as “parent-child” blocks.

3.6.6.6. Exclusive Choice Constraint (Exclusive blocks)

An exclusive constraint is a constraint defined over a list of bids (at whatever of the bid three levels defined above) that enforces that, at most, one bid in the list is accepted (at any non-zero level).

3.6.6.7. All-or-Nothing Constraint (List, Logical)

An all-or-nothing constraint is a constraint defined over a list of bids (at whatever of the bid three levels defined above) that enforces that either all of the bids in the list are rejected or all of the bids in the list are accepted (at any non-zero level). Note that an all-or-nothing constraint defined over a single multi-time-step-multi quantity bid can also be modeled by a minimum up time constraint with a duration equal to the bids time horizon.

3.6.6.8. Minimum income / Maximum payments constraints

The condition of minimum income enables bids to be submitted in all hours, provided that the production unit does not participate in the daily matching result if the total production obtained by it in the day does not exceed an income level above an established amount, expressed euros, plus a variable remuneration established in euros for every matched MWh. The condition of maximum payments is equivalent to the minimum income applied to energy purchases, which will not be matched if the cost is higher than a fixed value, plus one variable per matched kWh [17].

3.6.6.9. Maximum energy constraint

The maximum energy condition allows supply or acquisition units that have a limitation on the availability of energy, bid at all hours but limiting the matched value to an overall energy maximum. This condition is necessary due to the volatility of the prices of the intraday market between hours, which does not allow knowing the hours in which the production or acquisition units can match and, yet, there is a limit to the energy that can be sold, such as the case of pumping generation units [17].

3.6.6.10. Maximum/minimum price

According to [6], there shall be neither a maximum nor a minimum limit to the wholesale electricity price. This provision shall apply, inter alia, to bidding and clearing in all timeframes and shall include balancing energy and imbalance prices, without prejudice to the technical price limits which may be applied in the balancing timeframe and in the day-ahead and intraday timeframes in accordance with which is stated in the following paragraph. Nominated Electricity Market Operators (NEMOs) may apply harmonised limits on maximum and minimum clearing prices for day-ahead and intraday timeframes. Those limits shall be sufficiently high so as not to unnecessarily restrict trade, shall be harmonised for the internal market and shall take into account the maximum value of lost load. NEMOs shall implement a transparent mechanism to adjust automatically the technical bidding limits in due time in the event that the set limits are expected to be reached.

3.6.6.11. Single/dual imbalance price

According to [18], all TSOs shall develop a proposal to further specify and harmonize the use of single imbalance pricing for all imbalances, defining a single price for positive imbalances and negative imbalances for each imbalance price area within an imbalance settlement period.

In the case of the dual-price system, the imbalance price to be applied in each time-step is calculated in order to disincentive the aggravation of the system imbalance. When the imbalance has the same sign as the whole system imbalance, the imbalance is aggravating the whole system imbalance. Therefore, the price to be applied will be the corresponding imbalance price calculated reflecting the cost of balancing activated at that time-step. When the imbalance has opposite sign to the whole system imbalance, the imbalance is softening the whole system imbalance and it will be valued, frequently, at the day-ahead market price.

3.6.7. Objective Types

An objective in a market will always be a function of the activated bid fractions, the total bid quantities and the bid prices. There are different possibilities, given in the next subsubsections.

3.6.7.1. Maximizing Social Welfare

This is the most classical objective for energy markets. Social welfare is defined as the sum of producer surplus and consumer surplus, plus congestion rent. Producer surplus is the surplus over all supply bids. The surplus of a supply bid is the (positive) difference between the cleared price and the bid price, times the accepted amount of MW(h). The surplus of a demand bid is the (positive) difference between the bid price and the cleared price, time the accepted amount of MW(h). When this total surplus is maximized, the market seeks to combine as many supply side and demand side bids as possible, while still ensuring that no participant makes a loss.

3.6.7.2. Minimizing Activation Cost

Instead of maximizing the social welfare, the objective of the market could be to minimize the supply costs. This is equivalent to maximizing the social welfare in a case with inelastic demand. Nevertheless, in other cases, this objective may deviate substantially from the previous objective, particularly in the way that the surplus is split between the market parties.

3.6.7.3. Combined Objectives

In some cases, it will be desirable to strive for maximization of social welfare or minimization of activation cost, but still keep another secondary measure as low as possible or as high as possible. For example, in voltage control, to model the voltage and energy flows properly, these variables are co-constrained according to a second order constraint. Such a 'second order cone programming (SOCP)' model is sometimes used. In this model, any market solution needs the mentioned variables to be part of the edge of a conic shaped area and to stay within convex programming, which has its benefits, this can be reached only by adding a term to the objective so that it is co-optimized with the main objective.

3.6.8. Network representation in the market

The primary outcome of a market clearing is the decision of acceptance level of the bids submitted to this market. This implies a certain level of injection and/or offtakes in the nodes. This, in turn, affects the active and reactive energy flows on lines connecting these nodes as well as the voltages on the nodes. To ensure that the network can cope with these physical effects, one needs to model these physical aspects of the network together with the economic aspects of the bid in one unified mathematical model. This models economic and physical interdependencies (i.e. the interactions between the bids and the network representation). The focus here is on the physical, so network aspects.

3.6.8.1. Copper Plate

In reality, a network will most often consist of multiple buses connected by lines. The term '*copper plate*' is used for a simple network *model* that assumes that even though in reality this is the case, we treat such a network as if it was one node. Thus, we make abstraction of any internodal flows, losses and line congestions. Using this model basically ignores modelling any physical properties of the network. This means only the economic parts of the market clearing are modelled. In some cases, this may be a good enough as an initial model. However, to be sure that there is no serious congestion, losses or/and voltage problems, a more advanced network model than copper plate should be considered. If there is only one physical bus, a copper plate model is of course sufficient regarding the (non) modelling of the lines, since there are none.

3.6.8.2. Network Graph Representation

An electrical network with buses and lines can be represented by a (mathematical) graph as consisting of respectively, nodes and edges connecting these nodes. This is typically known as the power system one-line diagram. Nodes and edges can then be assigned some physical properties like parameters (e.g.: resistance and reactance for lines) and variables (e.g.: currents and active and reactive energy flows for lines and voltages for nodes). This will allow us to model the physical network behavior when acceptance of capacity/energy bids is being decided, so as to not exceed physical network limits.

We will consider the network graph of a network as it is operated. This means that, when a switch in a line is present and this switch is opened, we will consider that there is no edge in the graph connecting the nodes representing the end points of the line.

3.6.8.2.1. Available Transmission Capacity

The Available Transmission Capacity (ATC) network model represents lines in the sense that the energy flow from one node to a node connected to it by physical cable is limited by an upper and a lower bound. The lower bound can be negative and, in fact, puts an upper bound on the flow in the other direction. Upper and lower bounds need not sum to zero necessarily. Energy flow losses, line tariffs and line ramping constraints from one time step to the next can also be part of an ATC model.

Nevertheless, this ATC model neglects the fact that electricity flowing from e.g. node A to node B can actually create a flow on the line A to C as well. This is typically referred to as “loop-flow”, which is a physical flow of power that is not accounted for as part of the market. Therefore, this model is actually more decoupled from the “physics” and, somehow, models more accurately the “financial flows”. However, an ATC model has the advantage to ensure flows which are “intuitive flows” (a flow always goes from a cheaper node/zone to a more expensive zone/node) while a “flow-based” model can produce non-intuitive flows to which some market parties can be reluctant. See [19] for more details.

3.6.8.2.2. Flow-based Model

As an alternative network model to the ATC model, the Flow-based (FB) model can be used. This model is more accurate in the description of the flow distribution because on top of constraining the line flows by limits called Remaining Line Capacities (RAM), it also uses a Power Transfer Distribution Factors (PTDF) matrix that models how power distributes over the lines. See, [20] for more details.

3.6.8.2.3. Other Network Models

The previous models do not include voltage variables. For voltage control, we will obviously need to use a network model that has the voltage for every node as a variable.

One such model, which is applicable when voltage modelling and control is needed in radial networks is the Second Order Cone Programming (SOCP) model. Due to the quadratic relation between energy flows and voltages, this model is non-linear in its constraints. Linearizations of it exist and sometimes are accurate enough and faster in solving. See [21] for more details.

4. Markets design principles in CoordiNet

This chapter and the following one describe the relevant aspects of the market design implemented in the three demonstration campaigns of CoordiNet. While this chapter presents these aspects in a general way, the chapter 5 focuses more specifically on congestion management. This chapter therefore starts by presenting how the markets are currently organized in each demo country and how the markets implemented in CoordiNet are inserted in this existing framework. Then, the balancing responsibility split for demand, generation, storage, and aggregation is detailed. Note that, more information on interactions between the established markets and markets tested within CoordiNet and possible conflicts between them can be found on other deliverables more focused on specific demonstration campaigns. For Spain, Sweden and Greece the details can be found in Deliverable D3.2 [1], Deliverable D5.2 [3] and Deliverable D4.5 [22] respectively.

4.1. Description of the existing market timings

4.1.1. Spanish demonstrator

The timing of the existing markets and the new congestion management is shown in Figure 8.

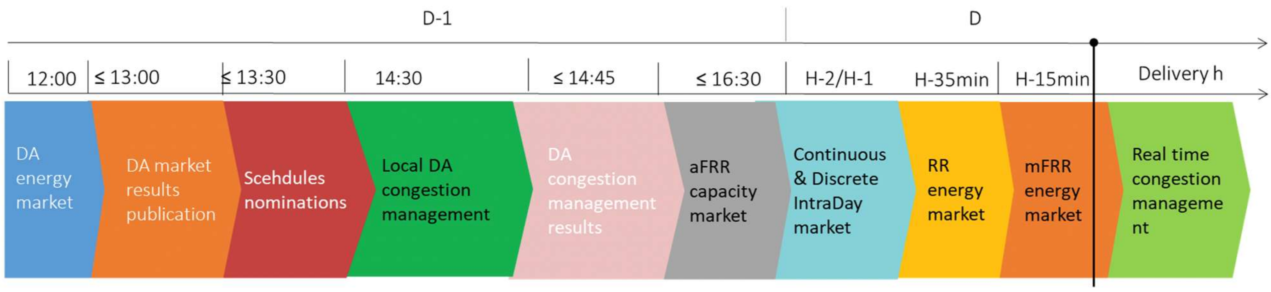

Figure 8: Timing of the Spanish market

In Spain, the day-ahead energy market gate closure is at 12:00 and the schedules nominations before 13:30. After the day-ahead market, new local congestion management market is expected to take place, where units connected at low voltage and with installed capacity of less than 1MW can participate. The common and existing congestion management market clears at 14:45 for generation resources with more than 1MW of installed capacity (CoordiNet opens the participation to demand-side resources). The congestion management market starts by computing the foreseen requirements from the TSO and DSOs and determining the effective local resources that can potentially solve the network constraints based on the power flow forecasts (before 14:00). These effective local resources will be determined from those that have been prequalified, while accounting for the impact on the identified congestion and the price they have offered. The TSO and DSOs inform the platform of the resources that have influence on the congestions.

The CoordiNet platform receive the needs and the effective local resources identified from the TSO and DSOs, as well as the bids from the FSPs. If bids are not enough to alleviate the foreseen congestions, then an emergency plan has to be activated. A detailed procedure and the definition of the clearing algorithm have to be defined to handle situations where potential conflicts emerge. For example, the same resources may be used to solve congestions that affect two networks in the opposite direction. Therefore, the overall system approach has to be considered. In the common market, all bids are put together in one pool and, then, the market is cleared to alleviate the congestions at both network levels. Once all the relevant constraints and available resources have been considered, the CoordiNet platform obtains the results and communicates them to the TSO and DSOs. Both grid operators will receive the results and check their feasibility. If there were any additional constraints, the market could be run again, depending on the situation.

From about one hour before real-time, the TSO manages the balancing of the system. It can be the case that a resource used for balancing will not be available anymore for congestion management or, by activating resources for congestion management, it can affect the balancing of the system. Therefore, the TSO has to establish a procedure to account for these circumstances. The final results are also sent to the concerned FSPs. The CoordiNet platform will also inform the TSO of the flexibility activations, who will also inform the (European) balancing platform to correct the corresponding short and long balancing positions. This is necessary to ensure that the BRPs whose position has been affected are not penalized for this reason. Each FSP has to perform the activation of resources manually or automatically. The platforms communicate the different activations to the TSO and DSOs who have to check the activation and monitor the system to verify the fulfilment of congestion management.

Once the services are delivered, the electricity generated or consumed has to be metered. In Spain, the entity that performs the metering activity depends on the consumption, generation and the grid level of the connection point. For consumers, metering activity is only performed by the DSO regardless of the grid level (transmission or distribution) to which they are connected. Metering for generators with capacity below 450kW is performed by the DSO, while all the rest is done by the TSO, regardless of the grid level (transmission or distribution) to which they are connected. The CoordiNet platform will then use the metering data to perform the settlement process of congestion management services with the FSP. Then, the FSPs will perform the individual settlement with the resources, which may include other services or even the energy sold in the day-ahead market or other contractual agreements. In other words, it is the FSPs' responsibility to settle with individual units all the different services provided.

4.1.2. Swedish demonstrator

The Swedish demonstration campaign follows a multi-level market model for the procurement of congestion management services from local and regional flexibility, which can also eventually be used as part of the Nordic mFRR market. The multi-level market has the timing shown in Figure 9.

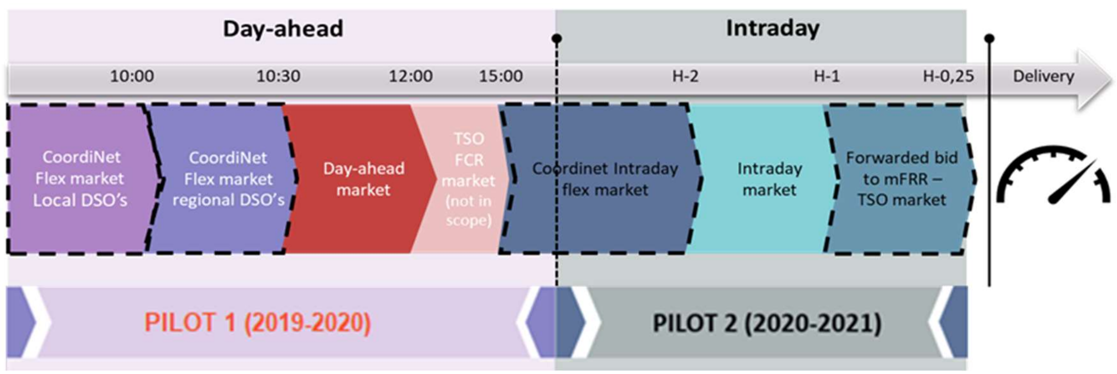

Figure 9: Timing of the Swedish flexibility market. Information based on [2]

The day-ahead flexibility market for congestion management receives bids for the multi-level (local DSOs-Regional DSO) market up to 9:30 a.m. day-ahead (D-1). Results of the clearing are published at 10:45 a.m. (D-1). In more detail, the local market clears at 10 a.m., while the regional market clears at 10:30 a.m. The bids submitted to the local market, which are not cleared in the local market, are automatically forwarded to the regional market level. The market horizon for bids at both local and regional segments consist of 24 periods of 60 minutes each. This day-ahead flexibility market will be cleared before the gate-closure time of the wholesale day-ahead market, allowing the involved parties to adjust their bids in the wholesale market based on the results of the flexibility market.

This day-ahead flexibility market will be complemented in demo run 2 (during the 2020-2021 winter) by a session of continuous intraday trading starting at 15:00 day-ahead, up until D-2h before real-time (closing before the Nordpool intraday market to reduce the interference with this latter energy market). During the day-ahead and intraday flexibility markets, the goal of the market is to allow the DSO to purchase local and regional flexibility to limit the power flow at certain connection points between the different grid levels (i.e., between the local and regional DSO and between the regional DSO and TSO) to prevent this flow from surpassing a maximum capacity known as the subscription level. Hence, the main goal of the market is to procure flexibility for congestion management. The flexibility needs of the DSO are determined based on a load prognosis and adjustments by the DSO. From the FSPs' side, the flexibility markets enable the FSPs to valorize their flexibility by offering it as a service to the grid operator(s). The day-ahead and intraday markets for flexibility trading are the focus of the BUC SE-1a.

In addition, during demo run 2 (winter 2020-2021), the flexibility bids used for congestion management will also have the chance, when prequalified, to be forwarded to the Nordic mFRR market (up to 1 hour before real-time) to provide balancing services. This service is the main focus of the BUC SE-3.

The day-ahead flexibility market (and its interconnection to the intraday flexibility trading and the subsequent forwarding of bids to the mFRR market) falls within the scope of a multi-level market model.

In addition, and somewhat independently from SE-1a and SE-3, peer-to-peer trading (following a distributed market model) for the management/prevention of wind power curtailment (i.e. between wind power producers and consumers) and management of limited grid capacity (i.e., between power producers), during scheduled maintenance periods is also planned to be tested as part of the Swedish demonstration campaign. This service is the main focus of the BUC SE-1b.

4.1.3. Greek demonstrator

The following Figure 10: Existing market structure in Greece provides an overview of the market structure in Greece. Let's first notice that while this is the current situation, the Greek markets are under major reforms and that they will be progressively uniformed with the market organization of the rest of Europe (in particular, the day-ahead market is expected to adopt to the European standards using the EUPHEMIA algorithm).

Nevertheless, the present market organization is as follows:

- **The day-ahead market**: it takes place every day and optimizes both reserve and energy. The objective is to minimize the total production cost, subject to inter-zonal transmission constraints, reserve requirements, and unit technical constraints.
- **Dispatch schedule**: after the market clears, the TSO has the possibility to adjust the dispatch schedule of the market. This adjustment is done with the bids of the day-ahead market. This can serve, for instance, for congestion management purposes.
- **Real-time dispatch**: the generating units can be re-dispatched by the TSO in real-time to meet actual system demand or for congestion management. This re-dispatch is performed with the reserve bids from the day-ahead market.
- **Imbalance settlement**: the imbalance price is determined after the real-time, based on the activations.

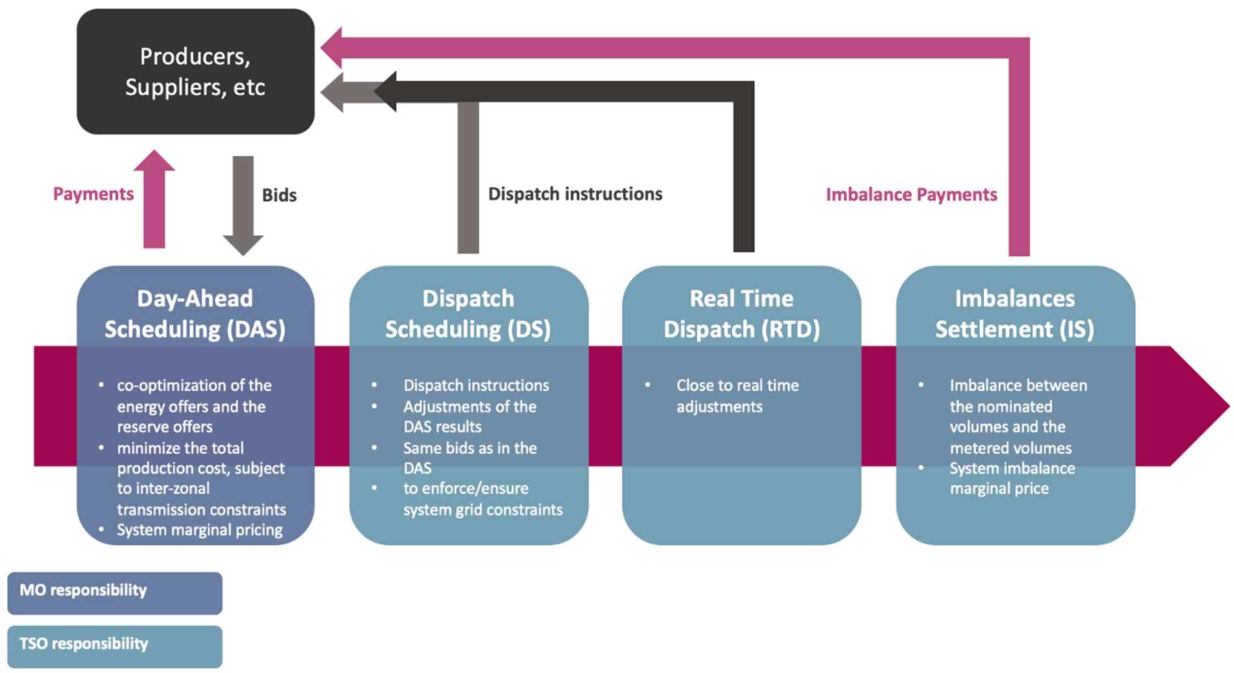

Figure 10: Existing market structure in Greece

In Figure 11: Time organization of the markets in Greece, the upper timeline shows the current status: the day-ahead market opens its gate at 10:30 in D-1 and closes at 13h in D-1. After it clears, the results are published by 14:00 D-1, which means that the dispatch schedule step should take place before 14h. The real-time dispatch takes place close to real-time, while the imbalance settlement is done just after real-time.

With Table 2: Timing of the markets in Greece, it shows how the congestion management markets (same holds for voltage control) developed in CoordiNet integrate in the previous timeline, while the next table gives accurately the frequency, granularity, opening, closing and result publication times of these markets. As far as the TSO is concerned, both the day-ahead markets sequence and the intraday market (the TSO holds a close to real-time dispatch, which can be used for congestion management) remain the same. Nevertheless, on the DSO side, while he is absent from the current congestion management process, in CoordiNet, the DSO organises: (1) a first congestion management market in day-ahead which opens at 16:00 and publishes its results by 23:30, (2) an intraday congestion management market early in the morning and (3) a close to real-time congestion management market.

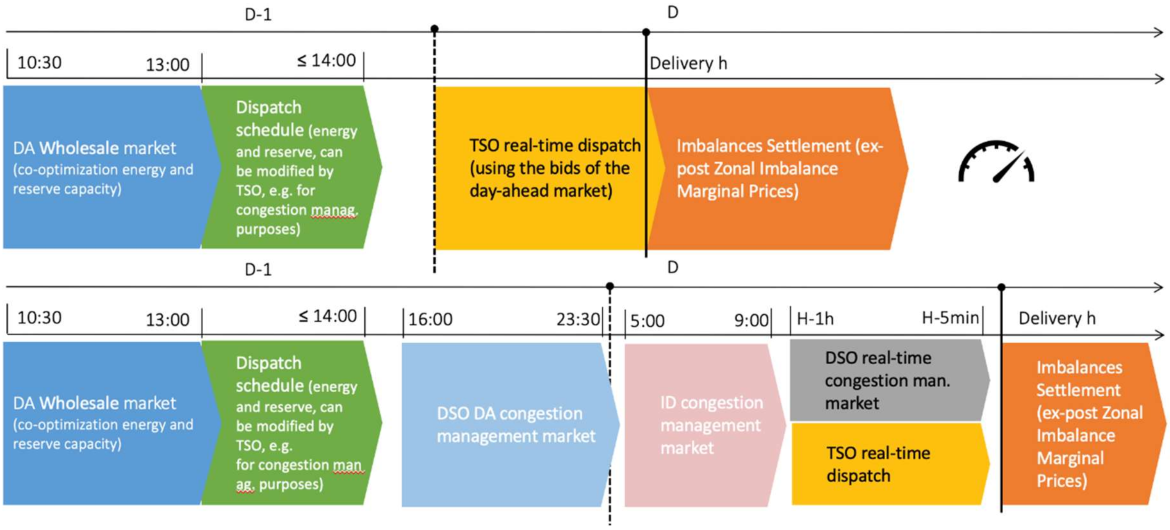

Figure 11: Time organization of the markets in Greece

Table 2: Timing of the markets in Greece

Coordination		Scope[2]	Frequency	Granularity	Gate opens	Gate closes	Result publication
Fragmented	DSO	D-A	Daily	1 h	16:00 D-1	23:00 D-1	23:30 D-1
		I-D	Daily	1 h	05:00 D	08:30 D	09:00 D
		R-T	15min	15 min	1h before H	15 min before H	5 min before H
	TSO	R-T	15 min	15 min	1h before H	15 min before H	5 min before H
Multi-level	DSO	D-A	Daily	1 h	16:00 D-1	23:00 D-1	23:30 D-1
		I-D	Daily	1 h	05:00 D	08:30 D	09:00 D
		R-T	15min	15 min	1h before H	15 min before H	5 min before H
	TSO	R-T	15 min	15 min	1h before H	15 min before H	5 min before H

4.2. Balance responsibility for demand, generation, storage, and aggregation

4.2.1. Spanish demonstrator

The scheduling process in the Spanish electricity system is based on the management of the programming units which are defined as the elementary unit of representation in the energy schedules [23]. The programming units allow the integration in the Spanish market of the energy sales or acquisition schedules corresponding to an individual facility or a set of them. They are also the basic unit for the annotation of the corresponding collection rights and payment obligations. There are different types of programming units:

[2] D-A = Day-ahead; I-D = Intraday; R-T = Real-time

1. Programming units for energy delivery[3]

In the case of *generation units belonging to facilities or groups of facilities from renewable sources (except for hydraulic management units), cogeneration and waste, of net power> 1 MW*, a single programming unit for the delivery of energy, by market participant and type of production is established. Therefore, each market participant will have as many programming units as types of production which make up its generation park, so that, each programming unit will integrate in the market the generation of a single type of production.

In turn, each programming unit of each market participant will be composed of one or more physical units with the same type of production as the programming unit. These physical units are:

- Each facility with a differentiated code in the administrative register of production facilities.
- Facilities belonging to the same cluster. A cluster is defined as the set of facilities connected to the same point of the distribution or transmission network, or that have a common evacuation line or transformer. The total power of the cluster will be the sum of the installed power of each facility that comprises it[4].

In addition, and respecting the criteria of market participant and type of production of the programming unit, where appropriate, as many programming units as necessary must be defined in order to distinguish between:

- Generation manageable / NOT manageable.
- Generation with/without dispatch priority.
- Generation enabled / NOT enabled for the participation in the ancillary services.

When the *generation units belong to facilities or groups of facilities from renewable sources (except for hydraulic management units), cogeneration and waste of net power less than or equal to 1 MW and that are not part of a cluster whose total sum of installed powers is greater than 1 MW,* a single generation programming unit will be set up by each market participant and type of production. Therefore, each programming unit will be composed of a single physical unit that will group all the facilities with a net power less than or equal to 1 MW of the same type of production and belonging to the same market participant. In this case also, where appropriate, as many programming units as necessary must be distinguished in order to differentiate between:

- Generation manageable / NOT manageable.
- Generation with/without dispatch priority.

2. Programming units for energy acquisition

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[3] Thermal plants > 100 MW will have one programming unit for each thermal group. In the case of the hydroelectric generation, there will be one single programming unit for the installations belonging to the same hydroelectric management unit.
[4] RD 413/2014, article 7.c [24]

*In the case of the energy acquisition by retailers, e*ach retailer will be the owner of a single programming unit for all its supplies within the Spanish electrical system. Similarly, each direct consumer in the market will be the owner of a single programming unit for all of its supplies.

3. Generic programming units

These units are used for the notification of use of assigned capacity in the interconnection between Spain and France and for the integration of the generation committed in bilateral contracts.

4. Portfolio programming units

These units are acquisition/Sale programming units for the acquisition/delivery in the continuous intraday market.

The settlement process of the system operator [25] is based on the programming units, which will be the elementary unit for recording the collection rights and payment obligations that correspond to each of them in the system operator's account. Likewise, the regulation zone will be the elementary unit for the annotation of collection rights and payment obligations corresponding to secondary regulation (aFRR) and deviations from the zone. Market participants will specify their actions in the market with respect to the system operator through programming units. Moreover, the programming unit will be the unit for assigning the measurements of each border point.

Each programming unit and each regulation area will be assigned to a single market participant, called *settlement unit agent*, as responsible for payments and collections. All annotations derived from the participation in the market of the programming unit will be made in the account of such agent. The imbalance assignation of each settlement agent will be the sum of the deviations of its programming units [26].

In March 2020, the Spanish TSO (Red Eléctrica de España) launched a proposal of the operating procedures to include the necessary changes for the participation of the demand and the storage in the balance services and their compatibility with the provision of the interruptible load service [27].

The organization criteria of the programming units are modified, so that programming units and physical units corresponding to demand facilities and, in anticipation of their regulatory development, to storage facilities will participate in the balancing services on equal terms with the generation and pumping consumption units, which are currently the only providers of balancing services in the Spanish electricity system. Some terms and definitions established in [6], such as market participant, balance responsible party (BRP) and balancing service provider, are adopted by the Spanish operating procedures.

When there is an unavailability in a specific programming unit, it is possible to make changes in schedules between BRPs through a double nomination process by the market participants. Changes can only be made in the energy schedules (established through contracts in the day-ahead market, intraday market or through bilateral contracts with physical delivery). Transfers of balancing energy allocations are not considered [23].

The operating procedure for the admission of participants in the market [28] is modified to define who is the responsible party with respect to the system operator, depending on whether it is a generation facility owner, retailer or direct consumer or the representative of any of them and, in the latter case, according to the modality of representation and depending on whether the participant is responsible for the balance or contractually delegates their responsibility to a BRP of their choice.

As established in [25], a BRP, in addition to being financially responsible for deviations from its programming units/regulation areas, will be responsible for payments, collections and the provision of payment guarantees that are derived from the participation in the market.

Optionally, and when requested by the BRP to the system operator, the collection rights and payment obligations for the imbalances of each one of the BRP's programming units and regulation areas may be calculated.

4.2.2. Swedish demonstrator

The TSO, Svenska Kraftnät is responsible for ensuring Sweden's short-term electricity balance, i.e. between supply (production and imports) and demand (consumption and exports), on an hourly basis. An electricity supplier may only supply electricity at connection points for which there is a Balance Responsible Party (BRP). Only those who have entered into an agreement with the TSO can be a BRP. The BRP has the financial responsibility for ensuring that the national electricity system is supplied with as much electricity as is consumed for the total of connections he is responsible for and this on an hourly basis and per market balance area (SE1, SE2, SE3, SE4). The electricity supplier can either take up that responsibility himself, and thus become a BRP, or contract a BRP.

A distinction is made between two types of balances (production balance and consumption balance) and plans for them have to be submitted separately to the TSO. Both are calculated and settled separately and priced differently:

- Production balance is the difference between the BRP's measured production and the binding plan for production per market area, corrected for any settled transactions regarding balancing energy provided to the TSO, the so-called imbalance adjustment.
- Consumption balance power is the difference between BRP's measured consumption and binding plan for consumption per market area, corrected for any settled transactions regarding balancing energy provided to the TSO.

More in detail, the BRP has to report the following plans to the TSO 45 minutes before the delivery hour [29]:

- Bilateral trades on retailer level, for the retailers the BRP is responsible for. There is a separate procedure to verify whether counterbids (from other BRPs) match[5].
- Plans per Regulation Object; A Regulation Object (RO) is a set of one or more generators and stations within a market balance area and can only include production of a certain technology (wind, hydro, nuclear, etc.).
- Regulation bids for up and down regulation, which are used to perform needed imbalance adjustments.

[5] Power exchange (day-ahead and intraday) trades are not part of this as the market operator is responsible to report these to the TSO directly.

Based on these inputs and final measurements, the production imbalance volume is calculated as the deviation between metered production, planned production and the imbalance adjustment. Consumption imbalance is calculated as the deviation between consumption, planned production, trades, “Metering Grid Area” imbalance[6] and the imbalance adjustment.

A different price model is applied to the production and consumption imbalances. The production imbalance volume is priced with the less favorable price of the market balance area’s power exchange market price and imbalance price and thus a dual pricing scheme is applied. The consumption imbalance volume is always priced with the market balance area's imbalance price according to a single pricing scheme.

As explained above, the imbalance position of the BRP is adjusted for the delivered balancing services (sum of FCR, FRR and RR). A similar mechanism is currently not in place to account for congestion management services provided to the DSO. Partly, this is however covered by the gate closure time (GCT) of the local and regional congestion market, which closes before the day-ahead market (see above), so that this service delivery can still be considered by the BRP. For intraday service delivery towards the DSO, the FSP could also update their BRP about the planned changes, so that this could be taken up in their plans which are submitted to the TSO. This process is however out of scope of the CoordiNet project.

4.2.3. Greek demonstrator

As of 1st November 2020, the Greek balancing market has commenced operation in accordance with the obligations and rules set within the Greek Target Model (Law 4425/2016). The explanatory document [31] [31] describes its main set of rules and some of them are summarized below.

Market participants

Every eligible party holding a license used in trading, production, supply or whether it is a RES aggregator, is referred as market participant. IPTO, the Greek system operator, is responsible for keeping up an “Operator Registry”, which is divided into 5 sub-registries describing the functions of each market participant:

1. The balancing service provider’s registry. Natural or legal persons able to provide balancing services shall be entitled to register with the balancing service provider’s registry; i.e. producers with an installed capacity of over 5MW (mandatory), RES producers not represented by a RES aggregator, auto-producers, RES aggregators, DR aggregators and consumers (including self-supplied providing DR services and not being represented by a DR aggregator).
2. The balance responsible party’s registry. The following natural or legal persons are obliged to be registered with the balance responsible party’s registry; producers with an installed capacity of over 5MW, RES producers not represented by a RES aggregator, auto-producers, RES aggregators, DR aggregators, consumers (including self-supplied providing DR services and not being represented by

[6] A Metering Grid Area is a physical area where consumption and / or production and exchange can be metered and can include both production and consumption but also only one of these and falls within a certain Market Balance Area [30].

a DR aggregator), suppliers, self-supplied customers, traders and RES Operator and Guarantees (DAPEEP[7]).
3. The balancing market generating unit's registry.
4. The dispatchable RES unit's portfolio registry.
5. The dispatchable load portfolio registry.

Every market participant must fulfil certain requirements in order to be included in the "Operator Registry". These requirements refer to legal, financial and technical prerequisites that the interested parties have to comply to. To obtain the status of Balancing Service Entity, the interested party must complete the pre-qualification process, which includes control tests to certify that the minimum technical requirements for the supply of FCR and FRR are fulfilled. The scope of the tests covers the generation and load balancing framework implemented by the Greek TSO (central dispatch model), and it also validates the relevant technical characteristics declared by the producer; the extent of reserves for the provided balancing energy services and the ramp-up and ramp-down rates of the generating units.

All agents participating in the market are subject to deviation imbalances.

<u>Storage in the Greek balancing market</u>

The Greek balancing market does not recognize storage providers as a separate legal or physical person.

Hydro resources are the only units that can submit both offers for balancing capacity generation and pumping (load). By extent, hydro resources are the only units that simulate a storage function. Other storage technologies remain largely unregulated within the Greek balancing market.

<u>Operation of the Greek balancing market</u>

Balancing market consists of:

- the balancing capacity market,
- the balancing energy market and
- the imbalance settlement.

The BSPs submit balancing capacity offers and balancing energy offers to the balancing market on behalf of the balancing service entities they represent. The offers are submitted to the Integrated Scheduling Process (ISP) and shall be taken into consideration for the execution of ISP1, ISP2 and ISP3, as well as for any ad-hoc ISP.

IPTO, in the context of the balancing market (as the Hellenic energy transmission system operator):

- executes ISP for the commitment (synchronization) or de-commitment (desynchronization) of balancing service entities and for the commitment of balancing capacity, and

[7] Operator of a portfolio of RES units, without market participation obligation.

- operates the balancing energy market for the activation of balancing energy offers for manual and automatic FRR and issues manual and automatic FRR dispatch instructions to balancing service entities.

The balancing capacity offers to the ISP for each balancing service entity and for each dispatch period shall consist of individual steps and shall refer to all types of balancing capacity (i.e. upward and downward FCR, upward and downward aFRR, upward and downward mFRR) for which their balancing service entities have the required technical capacity as per their registered characteristics. The minimum quantity of the balancing capacity offer shall be equal to 1MW. Regarding the submission of capacity offers:

- Dispatchable generating units that are registered with the balancing market generating units' registry are obliged to submit to the ISP.
- Dispatchable generating units with alternative fuel are obliged to submit separate balancing capacity offers for the operation both with the primary and the alternative fuel.
- Pumped storage dispatchable hydro generating units are obliged to submit separate balancing capacity offers for generation and pumping. The submission of balancing capacity offers for the pumping operation is not obligatory.
- Dispatchable multi-shaft combined cycle generating units are required to submit separate balancing capacity offers for each configuration of their units.
- Dispatchable RES units' portfolios are entitled to submit to the ISP.
- Dispatchable load portfolios are entitled to submit to the ISP.

The balancing energy offers to the ISP correspond to the intention to provide upward or downward balancing energy in relation to the market schedule of the respective balancing service entity. Regarding the submission of ISP balancing energy offers:

- Dispatchable generating units registered with the balancing market generating units' registry are obliged to submit to the ISP an upward ISP balancing energy offer and a downward ISP balancing energy offer.
- Dispatchable generating units with alternative fuel are obliged to submit separate balancing energy offers for their operation, both with the primary and the alternative fuel.
- Dispatchable hydro generating units are obliged to submit separate balancing energy offers for generation and pumping. The submission of balancing energy offers for pumping is not obligatory.
- Dispatchable multi-shaft combined cycle generating units are obliged to submit separate balancing energy offers for each configuration of their dispatchable generating units.
- Dispatchable RES units' portfolios are entitled to submit to the ISP an upward ISP balancing energy offer and a downward ISP balancing energy offer.
- Dispatchable load portfolios are entitled to submit to the ISP an upward ISP balancing energy offer and a downward ISP balancing energy offer.

The minimum quantity of the offer shall be equal to one 1MW. The quantity of the upward ISP balancing energy offer taken into account in the ISP corresponds to the difference between the available capacity of the balancing service provider and the capacity resulting from the balancing service provider's market schedule, as in force at the time of submission of the offer. The quantity of the downward ISP balancing energy offer corresponds to the difference between zero quantity and the capacity resulting from the balancing service provider's market schedule as in force at the time of submission of the offer.

The real-time balancing energy market is the market in which quantities and prices are determined for the activation of balancing energy by the respective balancing service providers, in order to balance energy supply and demand, taking into account the market schedules and the state of the Hellenic Electricity

Transmission System (HETS) in real time. The balancing energy market includes the manual FRR process and the automatic FRR process.

In the balancing energy market, the following products are used:

- The upward and downward balancing energy for manual FRR.
- The upward and downward balancing energy for automatic FRR.

Participation in the manual FRR process is mandatory for all dispatchable generating units having that obligation, in accordance with the HETS grid code, for all their available capacity, regardless of the balancing capacity awarded in the ISPs. Participation in the manual FRR process is optional for dispatchable RES units' portfolios and dispatchable load portfolios, except for the capacity volume corresponding to the manual FRR balancing capacity that they were awarded in the ISPs, for which participation is mandatory.

The manual FRR process shall adopt, without modification or review, the binding results of the ISP for each balancing service entity, unless the entity submits a partial or total non-availability declaration or a major outage declaration. The balancing capacity for FCR, automatic FRR, and manual FRR, determined in the ISP, shall remain in effect during all dispatch periods of the dispatch day. In case that a balancing service entity is not available due to a failure, the ISP may be executed again in order to award a balancing capacity for the FCR, automatic FRR and manual FRR that are actually available.

In the event that no balancing energy offers for manual FRR are submitted for dispatchable generating units at all, or if such offers are not submitted in time, or if they are not accepted, the ISP balancing energy offers per dispatch period shall automatically be converted into corresponding 15-minute energy market offers for manual FRR. Each ISP balancing energy offer per dispatch period shall be converted into two equivalent 15-minute balancing energy offers for manual FRR, in the same form and for the same balancing energy quantities and prices as those in the original offer.

In the event that, for two or more balancing energy offers pertaining to the same manual FRR time unit, the offer prices are identical and, at the same time, the respective balancing energy quantities of the above offers are not included in their entirety in the results of the manual FRR solution, the bidding segments shall be selected in the following order of priority: (a) Dispatchable RES units portfolio, (b) Dispatchable hydro generating units, (c) Dispatchable load Portfolio, and (d) Dispatchable thermal generating units.

Participation in the automatic FRR process is mandatory for all dispatchable generating units having that obligation, in accordance with the HETS grid code, regardless of the balancing capacity awarded in the ISPs. Participation in the automatic FRR process is optional for dispatchable RES units' portfolios and dispatchable load portfolios except for the capacity volume corresponding to the automatic FRR balancing capacity they were awarded in the ISPs, for which participation is mandatory.

In case the balancing energy offers for automatic FRR for the balancing service entities for which there was a corresponding obligation are not submitted in time or are not accepted, the ISP balancing energy offers per dispatch period shall automatically be converted into corresponding 15-minute energy market offers for automatic FRR. Each ISP balancing energy offer per dispatch period shall be converted into two equivalent 15-minute balancing energy offers for automatic FRR, in the same form and for the same balancing energy quantities and prices as those in the original offer.

4.3. Overview of the markets design in CoordiNet

As summary of the main market characteristics developed in CoordiNet for the different demonstrators, Table 3 and Table 4 show some of such characteristics in order to be easily comparable. Specifically, Table 3 compares the BUCs related to congestion management:

- BUC ES-1a: Congestion Management – Common Market Model,
- BUC ES-1b: Congestion Management – Local Market Model,
- BUC SE-1a: Congestion management – Multi-level Market Model,
- BUC SE-1b: Congestion management - Distributed Market Model,
- BUC GR-2a: Congestion Management – Multi-level Market Model,
- BUC GR-2b: Congestion Management – Fragmented Market Model,

while Table 4 shows the rest of the BUC related to other market services:

- BUC ES-2: Balancing services for the TSO,
- BUC ES-4: Controlled Islanding,
- BUC GR-1a: Voltage Control – Multi-Level Market Model,
- BUC GR-1b: Voltage Control – Fragmented Market Model.

Some of the BUCs have not been included in these tables, as they are not totally defined at the time of writing this deliverable (i.e. ES-2 Voltage control, SE-2 Balancing services for local DSO (in Gotland) – Local Market Model).

A more detailed information of each BUC can be found in next chapters. Specifically, for each BUC, an individual identity card has been developed merging its main characteristics. Chapter 5 shows such identity cards for the BUCs related to congestion management, since that is the most relevant service to be analysed within CoordiNet project, while the rest of the analysed BUCs have been moved to appendixes (Appendix A – Spanish market design ID cards, Appendix B – Swedish market design ID cards and Appendix C – Greek market design ID cards).

Table 3: Market characteristics - Congestion management BUCs

BUC			ES-1a	ES-1b	SE-1a	SE-1b	GR-2a	GR-2b
BUC case			Day-ahead (D-A) Real Time (R-T)	Day-ahead (D-A) Intraday (I-D)	Day-ahead (D-A) (demo run 1) Intraday (I-D) (demo run 2)	Peer-to-peer	Day-ahead (D-A) Intraday (I-D) Real Time (R-T)	Day-ahead (D-A) Intraday (I-D) Real Time (R-T)
Market service / Product type	Congestion management	Reserved (capacity)		X	X	X	X	X
		Non-reserved (energy)	X	X			X	X
Coordination scheme	Central							
	Common		X					
	Multi-level				X		X	
	Fragmented							X
	Distributed					X		
	Local			X				
Market participants	Demand-side		TSO + DSOs	DSOs	DSOs	DSOs	TSO+DSO	TSO+DSO
	Supply side		FSPs + Aggregator	Aggregator	FSPs	FSPs / Aggregator	FSPs	FSPs
	Market Operator		TSO	DSOs	Regional/Local DSO	Regional/Local DSO	TSO+DSO	TSO+DSO
	Observer		-	TSO	TSO	-	-	-
Timing	Market horizon		24h (D-A) Next hour (R-T)	24 h (D-A) 15 min (I-D)	24 h (D-A)	1 hour	24h (D-A) Multiperiod (I-D) 15 min (R-T)	24h (D-A) Multiperiod (I-D) 15 min (R-T)
	Time granularity		1 hour	15 min	1 hour	1 hour	1 hour (D-A) 1 hour (I-D) 15 min (R-T)	1 hour (D-A) 1 hour (I-D) 15 min (R-T)
	Gate closure time		13:15, D-1 (D-A) No market opens (R-T)	14:30, D-1 (D-A) H-30 min. (I-D)	9:30 (D-A) H-2h (I-D)	H-15 min	23:00, D-1 (D-A) 8:00, D (I-D) H-15 min (R-T)	23:00, D-1 (D-A) 8:00, D (I-D) H-15 min (R-T)
	Market frequency		Once per day, everyday (D-A) Whenever needed (R-T)	Once per day, everyday (D-A) 96 per day, everyday (I-D)	Once per day, 5 days a week	Whenever needed	Once per day (D-A) Once per day (I-D) Every 15 min (R-T)	Once per day (D-A) Once per day (I-D) Every 15 min (R-T)

BUC		ES-1a	ES-1b	SE-1a	SE-1b	GR-2a	GR-2b
Trading type	Unit- vs. Portfolio-based	Portfolio-based	Portfolio-based		Portfolio-based	Portfolio-based	Portfolio-based
	Bilateral vs. Multilateral	Multilateral	Bilateral	Bilateral		Bilateral	Bilateral
	Symmetric vs. Asymmetric	Symmetric	Symmetric	Asymmetric	Asymmetric	Symmetric	Symmetric
Auction type	Closed gate vs. Continuous	Closed gate	Closed gate	Closed gate (D-A) Continuous (I-D)	Continuous	Closed gate	Closed gate
	Independent vs. Rolling	Independent	Independent			Independent	Independent
Centralization level		Centralized	Centralized (at local level)	Centralized (at local level)	Peer-to-peer	Centralized (at local level)	Centralized (at local level)
Market pricing	Pay-as-cleared vs. Pay-as-bid	Pay-as-bid	Pay-as-cleared	Pay-as-bid	Pay-as-bid	Pay-as-cleared	Pay-as-cleared
	Nodal vs. Zonal	-	Nodal at network representation level	-	-	Zonal (whole system)	Zonal (whole system)
Bid Types	Single-quantity						
	Multi-quantity						
	Block bids	Block bids	Block bids (a volume, a price limit, a list of adjacent periods and a fill-or-kill constraint)	Block bids		Block bids	Block bids
Market Objective	Maximize social welfare vs. Minimize activation cost (vs. combined)	Minimize activation cost	Minimize activation cost	Minimize activation costs	Social welfare	Minimize activation cost	Minimize activation cost
Network types	Copper plate vs. Available Transmission Capacity (ATC) vs. Flow-based	Flow-based (transmission) ATC (distribution)	Flow-based	ATC	ATC	Flow-based	Flow-based

Table 4: Market characteristics - Other BUCs

BUC			ES-2		ES-4	SE-3	GR-1a	GR-1b
BUC case			mFRR	RR	Long-term	mFRR	Day-ahead (D-A) Intraday (I-D) Real Time (R-T)	Day-ahead (D-A) Intraday (I-D) Real Time (R-T)
		mFRR	X			X		
		RR		X				
	Voltage control	Steady-state reactive power					X	X
		Dynamic reactive power						
		Active power					X	X
	Controlled islanding	Capacity product			X			
Coordination scheme	Central		X					
	Multi-level					X	X	
	Fragmented							X
	Local				X			
Market participants	Demand-side		TSO		DSO	TSO + DSOs	DSO+TSO	DSO+TSO
	Supply side		FSPs + Aggregator		Aggregator + DSO (battery)	FSPs	FSPs	FSPs
	Market Operator		TSO		DSO	TSO + DSOs	DSO+TSO	DSO+TSO
	Observer		DSO		TSO	--	--	--
Timing	Market horizon		24h	Up to next I-D session	Year	1 hour	24h (D-A) Multiperiod (I-D) 15 min (R-T)	24h (D-A) Multiperiod (I-D) 15 min (R-T)
	Time granularity		1 hour	1 hour	1 hour	1 hour	1 hour (D-A) 1 hour (I-D) 15 min (R-T)	1 hour (D-A) 1 hour (I-D) 15 min (R-T)
	Gate closure time		T-25 min	T -60 min		H-45 min	23 h, D-1 (D-A) 8:30 h, D (I-D) H-15 min (R-T)	23 h, D-1 (D-A) 8:30 h, D (I-D) H-15 min (R-T)

BUC		ES-2		ES-4	SE-3	GR-1a	GR-1b
	Market frequency	Once per day, every day	Whenever needed	Once per year	Once per hour	Once per day (D-A) Once per day (I-D) Every 15 min (R-T)	Once per day (D-A) Once per day (I-D) Every 15 min (R-T)
Trading type	Unit- vs. Portfolio-based	Portfolio-based		Unit-based	Portfolio	Portfolio-based	Portfolio-based
	Bilateral vs. Multilateral	Multilateral		Bilateral	Multilateral		
	Symmetric vs. Asymmetric	Symmetric		Symmetric	Asymmetric		
Auction type	Closed gate vs. Continuous	Closed gate		Closed gate	Closed gate	Closed gate	Closed gate
	Independent vs. Rolling	Independent		Independent	Independent	Independent	Independent
Centralization level		Highly centralized		Centralized at local level	Centralized	Centralized (at local level)	Centralized (at local level)
Market pricing	Pay-as-cleared vs. Pay-as-bid	Pay-as-clear		Pay-as-bid	Pay-as-clear	Pay-as-clear	Pay-as-clear
	Nodal vs. Zonal	Zonal (whole system)		--		Zonal (whole system)	Zonal (whole system)
Bid Types	Single-quantity						
	Multi-quantity						
	Block bids	Block bids			Block bids	Block bids	Block bids
Market Objective	Maximize social welfare vs. Minimize activation cost (vs. combined)	Minimize activation costs		Minimize activation costs	Minimize activation costs	Minimize activation cost	Minimize activation cost
Network types	Copper plate vs. Available Transmission Capacity vs. Flow-based	Flow-based		--	--	Flow-based	Flow-based

5. Description of Market design for congestion management in CoordiNet

While chapter 4 introduced some general design principles of the three demonstration campaigns, this chapter aims at detailing more specifically how the congestion management markets are implemented in each demonstrator. The description is organized as identity (ID) cards per demonstration action.

5.1. Congestion management in the Spanish demonstrator

5.1.1. ES-1a – Congestion Management market ID cards

In this subsection, we expose the market dimension chosen for the central market (operated by the TSO) of the BUC ES-1a.

Market service
The main focus of BUC ES-1a is congestion management. As opposed to ES-1b, in this BUC the market is run centrally by the TSO.

Market participants
- The DSOs (e-distribución and i-DE). The DSOs will include their congestion needs into the CoordiNet Platform. - Different FSP participate in this market either directly or through an aggregator - The TSO (Red Eléctrica de España), who acts both as a buyer of flexibility and market operator.

Coordination scheme
The implemented coordination scheme is the **common market model** (cf. Deliverable D1.3 [12]). This means that the market will be operated centrally. On one hand, the TSO runs its congestion management market daily, after the day ahead market clearing, and after that, in real-time if needed. On the other hand, the DSO will be able to call congestion management needs through the CoordiNet platform.

Market timing

For this BUC, the market is defined by closed-gate auctions, with a 24 hours horizon (i.e. day-ahead market) and an intraday horizon. The auctions have independent horizons. As for the time granularity (i.e. the time steps), it should be of 1h:
 	
• Day-ahead market:
  ○ **Market frequency**. The market will be used every day, once a day, from Monday to Sunday in day-ahead.
  ○ **Market clearing time**. From 12:00 to 13:15 CET of D-1. The market clearing process is composed of two different phases, in accordance with the current congestion management market (Deliverable 3.1).
  ○ **Market horizon**. This is the number of periods which are considered in a single market session. The day-ahead market is a multiperiod market and will include 24 periods of 1h.
 	
• Real-Time congestion management:
  ○ **Market frequency**. No market is specifically open for the real-time scope. According to the system's need (both from TSO and DSO), the TSO can clear and activate bids provided in the day-ahead congestion management market.
  ○ **Market clearing time**. Market clearing is done on-demand. The TSO carries a real-time monitoring of the system, identifying the needs for congestion management activation. The DSO also carries a real-time monitoring of its network, and whenever congestions are identified, these are declared through the CoordiNet platform, for the TSO to run the clearing algorithm.

Market dimensions	
Trading Type	A **portfolio trading** approach is used.
Auction Type	The market is defined by **closed-gate auctions.** The auctions have **independent horizons**.
Centralization level	As detailed in the BUC definition, is **centralized**.
Market pricing	The market pricing follows the **pay-as-bid** scheme.

Bid types	Bids include: Type of offer (production, consumption, or import) Upward energy: • Energy (MWh) • Time-periods • Price Downwards energy: • Energy (MWh) • Time-periods • Price In case of thermal generators, complex bids are accepted. In this case, start-up costs are also sent.
Objective type	The goal when selecting the accepted bids is to **minimize the system's costs.**
Network representation in the market	Sensitivity factors applied to DERs depending on the contribution to solve congestions are determined by the DSOs and TSO. The methodology is pending to be determined at the time of writing this report.

5.1.2. ES-1b – Congestion Management market ID cards

In this subsection, we expose the market dimensions chosen for the local market (at the DSO level) of the BUC ES-1b.

Market service
The main focus of BUC ES-1b is congestion management. To help to tackle this issue, a local market that will bring flexibility for market operators is developed. The purpose of the trading would be to locally increase or decrease energy to avoid problems regarding the line capacities of the grid.

Market participants

For the DSO local market, the actors are as follows:

- The DSOs (e-distribución and i-DE) for the demand side of the market.
- The FSPs are represented by an aggregator (TECNALIA and Our New Energy) who plays the supply side of the market.
- The TSO (Red Eléctrica de España) is passive in this BUC and only receives the market outputs.
- Market operator (IREC, also in charge of the local platform).

Coordination scheme

The implemented coordination scheme is the **local market model** (cf. Deliverable D1.3 [12]).

This means that the local market will connect the DSO (looking for flexibility) and the aggregator (the flexibility supplier). After the clearing of the market, the result of the clearing will be transmitted to the TSO, but the bids will not be sent automatically to the TSO platform.

Market Product

Two products for congestion management have been defined (in D1.3):

- **Congestion management reserved** (capacity-based product)
- **Congestion management non-reserved** (energy-based product)

Market timing

For this BUC, the market is defined by closed-gate auctions, with a 24-hours horizon, i.e. day-ahead market, (capacity product) and an intraday horizon (energy product). In more details:

- Day-ahead market:
  - **Market frequency**. The market will be used every day, once a day, from Monday to Sunday in day-ahead.
  - **Market clearing time.** The market would clear at 14:30 UTC. Let's notice that the TSO clears the common market at 15:00 and that the European day-

ahead market (EUPHEMIA) send results at 14:00, so it means the local market will lay in between the day-ahead and the TSO common market. o **Market horizon.** This is the number of periods which are considered in a single market session. The local day-ahead market is a multi-period market. • Intraday market (not final): o **Market frequency**. The market will be used every 15 minutes every day, from Monday to Sunday (which means 96 intraday market sessions per day). o **Market clearing time**. The market would clear 30 minutes before each market session delivery time (e.g. the session of 14:00 clears at 13:30). o **Market horizon**. The local intraday market is a single period market: it includes 1 period of 15 minutes. Note that for the maximum market-clearing duration, given the fact that we deal with a local market with a small number of assets, a(n) (optimal) solution should be found in less than ten minutes.

Market dimensions	
Trading Type	Because we are dealing with an aggregator on the supply side and the fact that different kinds of assets are used in this local market, we use a **portfolio trading** approach. The market be **bilateral** and **symmetric**.
Auction Type	The market is defined by **closed-gate auctions.** The auctions have **independent horizons**.
Centralization level	As detailed in the BUC definition, this local market is **highly centralized** (at a local level).
Market pricing	This market is defined by a **uniform pricing rule** (**pay-as-cleared**) with a **nodal pricing** approach over the network representation given to the clearing engine.

Bid types	Every market product (bid) is constituted of a location (node in the network) and a time period. Given our market design, the bids for the **demand side** are additionally defined by a volume (MW) and eventually an upper bound on the price (€ per MW). These are stepwise curves. The bids for the **supply side** are **step order** bids (a volume and a price limit). **Block order** (a volume, a price limit, a list of adjacent periods and a fill-or-kill constraint)
Objective type	The goal when selecting the accepted bids is to **minimize total supply cost**, with the additional constraint that every accepted order must be economically interesting (i.e. in/at the money)
Network representation in the market	At the time of writing this report, the best guess is that a mathematical graph will be used to represent the physical network. This representation may differ from the physical reality for efficiency and simplicity reasons. Some nodes have been aggregated and some lines have been removed in the representation to obtain a **radial network**. Because the main focus of this BUC is congestion management, each line in the network representation needs to have a **maximal energy flow constraint** and only consider **active power**. The model takes the **power balance equation** into account. Because the voltage is not used in the model, we use a **loss factor** for taking energy loss into account (e.g. 5% loss on the overall system). We use **Available Transmission Capacity** to model the flow into the grid.

5.1.3. Product attributes for local congestion management

The local platform for congestion management considers the congestion management reserved. This is a capacity-based product procured for congestion management services at a certain availability price which is then activated when the service is needed by the relevant system operator. This product is defined to cope with structural constraints, the details of this product are shown in Table 5.

Table 5: Attributes of local congestion management reserved product

Attribute	Value
Preparation period	Day-ahead until hour ahead.
Ramping period	0 to 30 minutes
Full activation time	0 to 30 minutes
Minimum quantity	1kW

Maximum quantity	1MW (including aggregation). Additionally, the sum of installed capacity in the local market shall be less than 1MW.
Deactivation period	0 to 15 minutes
Granularity	1 kW
Minimum duration of delivery period	15 minutes
Maximum duration of delivery period	6 hours
Mode of activation	Automatic from the local platform to the aggregator, manual or automatic from the aggregator to the sFSP
Availability price	Yes
Activation price	Possible, dependent on the procurement process.
Divisibility	Divisible and indivisible bids are allowed.
Location	Included in the bid[8].
Recovery period	From 15 minutes to 2 hours
Aggregation allowed	Yes, but depending on the grid congestion to be solved and whether the resource has an impact on the congestion.
Product symmetry	No symmetry required.

5.1.4. Product attributes for common congestion management

In Spain, non-reserved congestion management service is currently traded in the common market. This is an energy-based product procured for congestion management services at an energy price (most likely to be procured closer to delivery given the fact that it is energy based). A summary of product attributes is shown in Table 6.

Table 6: Attributes of the congestion management non-reserved product

Attribute	Value
Preparation period	Not defined. The SO takes into account the flexibility of the different units.
Ramping period	Not defined. The SO takes into account the flexibility of the different units.
Full activation time	Not defined. Can vary from real time up to 31 hours.
Minimum quantity	0.1 MW
Maximum quantity	N.A.
Deactivation period	Not defined. Depends on the capability of the different units.
Granularity	0.1
Minimum duration of delivery period	NA
Maximum duration of delivery period	NA
Mode of activation	Manual
Availability price	No. All the units must participate according to their schedules and maximum available power or production forecast.
Activation price	Yes. Bid price except for downwards energy in phase I of technical constraints process in D-1 (upwards energy in the case of pumping units), where the day-ahead market price is the clearing price.

[8] At least the smallest granularity relevant from grid operation perspective.

Divisibility	Only divisible bids are allowed. Depending on the previous schedule of the unit, a complex bid could be used for thermal units (start-up costs, number of scheduled hours and energy price)
Location	NA
Recovery period	NA
Aggregation allowed	Yes
Symmetric / asymmetric product	No symmetry required

5.2. Congestion management in the Swedish Demonstrator

5.2.1. SE-1a Congestion Management market ID cards

In this subsection, the market dimensions chosen for the day-ahead market of the BUC SE-1a are presented, based on the information implemented as part of the first run of the demonstration campaign (running during winter 2019/2020). Additional information is also provided, when relevant, for the foreseen intraday market planned for the second run of the demonstration campaign (winter 2020/2021). The information introduced here is based on information provided through [2] as well as on inputs provided by WP4 partners (Yvonne Ruwaida and Nicholas Etherden).

Market service
The main focus of BUC SE-1 a is congestion management with the goal of preventing the interface power flow between the local DSO(s) and regional DSO and between the regional DSO and TSO from surpassing a pre-set limit known as the subscription capacity or the subscription level. Towards this goal, a multi-level market is developed that aims at bringing flexibility for market operators (i.e. local DSO and regional DSO). The purpose of the trading is to locally decrease energy demand or increase energy production to avoid constraint violation defined by the subscription level of the overlying grid.

Market participants
For the DSO local and regional markets, the actors are as follows: • The DSOs: Vattenfall Distribution, E.ON Distribution and GEAB for the demand side of the market. • The FSPs which constitute the supply side of the market. • The TSO (Svenska Kraftnät) participates by providing information on whether it is possible to surpass the subscription between the DSO regional grid and the TSO national grid. • The market operator is the regional DSO in Uppland and Skåne and the local DSO in Gotland.

- The grid prognosis providers consist of external actors with prognosis competence: RTWH Aachen and Expektra
- The platform provider is EON Energidistribution

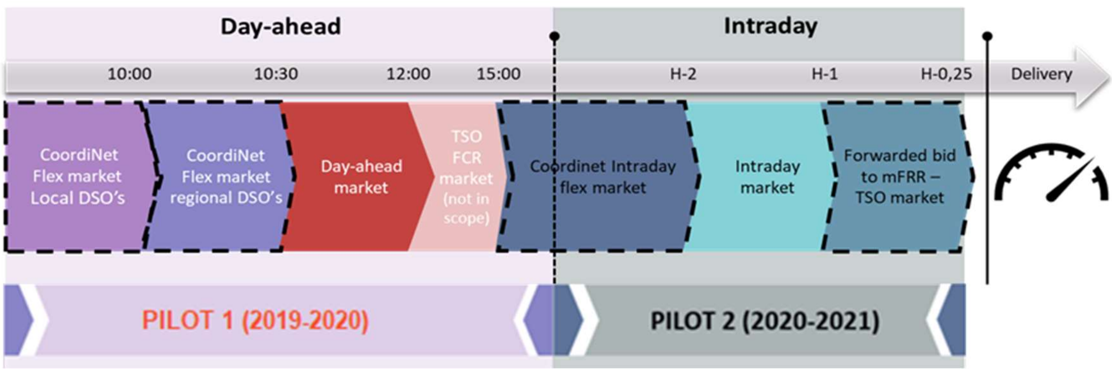
Coordination scheme

The implemented coordination scheme is a multi-level market model (cf. Deliverable D1.3).

The market will connect the local and regional DSOs (looking for flexibility) with the flexibility providers in a sequential manner. After the clearing of the local DSO market, the remaining unused bids will be automatically passed to the regional DSO. The main difference between the multi-level coordination scheme implemented here and the one proposed in D1.3, is the fact that this scheme does not allow the FSPs to modify their bids between the local and regional markets clearing. Bids are submitted to the platform at once, based on which they are passed first to the local flexibility market, and the remainder unused bids (the bids that are not cleared in the local flexibility market) are passed to the regional flexibility market.

Uncleared bids from the day-ahead flexibility sessions could be automatically passed to the intraday flexibility market trading, if the FSPs choose to opt for this option. FSPs can still modify their intraday bids when automatically forwarded to the intraday session, or they can choose to place new bids if their bids are not forwarded.

The timeline of this process is shown next, placed with respect to the existing wholesale electricity markets.



Market timing

The market is defined by closed-gate auctions, with a day-ahead horizon (i.e. day-ahead market), during demo run 1 (an intraday horizon up to 2 hours before delivery is planned to be considered in demo run 2). The time granularity (i.e. the time steps), in the day-ahead market follows a sequence of 60-minutes periods. In more details:
 	
• Day-ahead market:
  ○ **Market frequency**. The market will be used once a day, 5 days a week, in demo 1 and every day in demo run 2.
  ○ **Gate closure time**: 09:30 am
  ○ **Market clearing time.** The local market clears at 10:00 and the regional market clears at 10:30 am.
  ○ **Market horizon**. The local day-ahead market is a multiperiod market and will include 24 periods of 60 minutes (from D+1 00:00 to D+1 23:59)
 	
As for intraday flexibility trading: The intraday market opens daily at 15:00 for the next day, up until D-2 hours, following a continuous trading scheme.

Market dimensions	
Trading Type	For the day-ahead flexibility trading, the DSO receives the bids from different FSPs and BSPs (which use an aggregation of different units) and selects the bids to be activated following an automatically generated merit order list and based on the DSO's identified need. In more detail, based on the submitted bids and the impact factor of each of the assets, a merit order list and a suggestion for the list of bids to be cleared to meet the DSO's need are automatically generated. This recommendation for which bids to clear has to be cleared manually by the DSO, as the DSO has the possibility to change the automatically generated matching. The reason for that is to allow the DSO to adjust for various events - such as production plans not submitted in time to be used in the forecasts, unforeseen problems on the FSPs' side, etc. The impact factor used quantify the effect of activation of a certain flexibility on the flow at a certain connection point between two grid levels. The intraday market follows a continuous trading scheme. For the DSO, at any time in intraday, the DSO receives a list of recommended bids in intraday to purchase.
Auction Type	The day-ahead market is defined by **closed-gate auctions.** The intraday market follows a continuous trading scheme.

Centralization level	The market is **centralized** (at a local level) and is run by the regional or local DSO. The DSO receives the bids and selects the ones to be activated based on a merit order list taking into consideration the impact factor of each bid and the DSO's identified flexibility needs.
Market pricing	This day-ahead market follows a pay-as-cleared pricing.
Bid types	On the supply side: All bids are capacity bids. 1-hour bids (a volume, in MW, and a price in SEK/MW for 1 hour) and block orders (spanning multiple hours) are considered. Block orders could be partially accepted. However, the same level of acceptance must be applied over the entire time period of the block. Every bid is associated with an impact factor and a time period. Submitted bids specify the minimum and maximum bid quantities as well as the offered price. Additionally, step sizes for activation could be specified. Demo run 2 during winter 2020/2021 plans to allow the additional specification of temporal constraints such as minimum cooldown times and maximum sustained delivery times (more information regarding these types of specification to appear in D4.1 of CoordiNet). Long-term capacity contracts of availability, as operation reserves or conditional connection agreements, are also included in the market. The former is set by the DSO at a high price and the latter is set at or below the price of the subscription level penalty (i.e. the penalty payed for surpassing the subscription level). On the demand side, the demand is inflexible and no demand bids are submitted. On the day-ahead market, the DSO's need is based on forecasts and on an added security margin. The only buyer is the DSO (local or regional).
Objective type	The goal when selecting the accepted bids is to minimize the amount of flexibility purchased or, equivalently, the cost of acquiring the flexibility by the DSO.
Network representation in the market	Impact factors (taking values between 0 and 1) are used, which capture the effect of activation of flexibility by a certain flexibility asset on the power flow through a certain connection point (whose flow should be limited following the defined subscription level). Hence, in the market clearing process, each provider is associated with an impact factor (determined during a prequalification or planning phase). The submitted price of a bid is divided by its impact factor, while the submitted quantity is multiplied by the impact factor to determine the actual impact on

	the flow through the connection point that a flexibility bid would be able to deliver. The impact factors are, hence, incorporated in the calculation of the merit order list.

5.2.2. SE-1b Congestion Management Market ID cards

In this subsection, the market dimension chosen for the market of the BUC SE-1b are presented. The information introduced is based on information provided through D4.1[9], as well as on inputs provided by WP4 partners (Yvonne Ruwaida and Nicholas Etherden).

Market service
The main focus of BUC SE-1 b is congestion management among peers when production is curtailed. The purpose of trading in the Northern peer-to-peer market is to give flexibility for producers to either sell their capacity or to buy capacity during curtailment period. The purpose of trading in the Gotland peer-to-peer market is for the wind power local energy community to produce more during curtailment periods when capacity can be bought from consumers by consuming more. In both cases, it is a capacity market during curtailment periods. The DSO gives information on curtailment periods and is not a part of the peer-to-peer market.

Market participants
For the peer-to-peer market, the actors are as follows: - The DSOs: E.ON Distribution and GEAB giving information on curtailment periods. The DSO provides the market platform but is not an actor in the market. - The market operator is the regional DSO in Northern Sweden and the local DSO in Gotland. - The FSPs (Gotland): the local district heating unit. - Power producers (Gotland): Gotland wind producer's association. - Power producers (Västernorrland and Jämtland): wind power producers and hydro plants.

[9] This deliverable is not published at the time of writing this report. However, it will be made available in the deliverables section of CoordiNet's website (https://coordinet-project.eu/publications/deliverables).

Coordination scheme
The implemented coordination scheme is the **distributed market** (cf. Deliverable D1.3).

Market timing
The market is used when needed, e.g., during curtailment periods and is based on continuous trading.

Market dimensions	
Trading Type	The market is based on continuous trading.
Auction Type	Continuous market.
Centralization level	The DSO sets-up the market, but trading is not centralized (it is peer-to-peer).
Market pricing	Pay as bid.
Bid types	Hourly flexibility bids are considered. The DSO gives information that there is curtailment to be done. Producers are curtailed as single or aggregated entities. The purchasing need in Gotland is aggregated all together (among wind turbines). On the flexibility supply side: consumers are not aggregated. The purchasing entity wanting to buy capacity receives the bids from other FSPs and selects the bids to be activated.

Objective type	The goal when selecting the accepted bids is to minimize the cost of curtailment for the buyer of capacity. For the seller of capacity, it is to maximise profit. The goal of the DSO is to participate in using the grid more efficiently and decreasing curtailment in Gotland and in North of Sweden giving the producers a choice to optimize the situation during curtailment.
Network representation in the market	This market does not require a specific representation of the network. The main grid requirement is the assessment of the increase or decrease in production/consumption on the constrained grid (or line) capacity.

5.2.3. Product attributes for congestion management

The multi-level flexibility platform for congestion management in Sweden, i.e., in BUC SE-1a, accepts two day-ahead products: congestion management long-term capacity bids and congestion management free bids.[10] As previously stated, the goal of congestion management in this use case is to adjust load levels of the local DSO and regional DSO grids so as not to surpass the allowed subscription capacity with, respectively, the regional DSO and the TSO.

5.2.3.1. Congestion Management Long-term Capacity bids

The congestion management long-term capacity bids are supported by availability agreements between the FSP and the DSO. Basically, these agreements allow the DSO to control consumption and production according to the grid needs and based on the attributes of the contract. At market level, only the provision of this product is remunerated, i.e., actual delivery of flexibility (in addition to the specifics of the availability contract). The DSO uses this product to manage the subscription capacity at the interconnection level (substation(s) between local and regional and between regional and transmission grids). Table 7 shows the attributes of the product congestion management long-term capacity bids, which is obtained from CoordiNet D4.1. Relevant information is also available in [32].

Table 7: Attributes of congestion management long-term capacity products

Attribute	Value
Preparation period	Day-Ahead: Bids submitted 9:30 day before. Information of cleared bid after 10:30 the day before delivery Intraday: clearing two hours before delivery time
Availability	99%
Ramping period	None
Full activation time	None
Minimum quantity	Minimum 1 MW
Maximum quantity	Not defined

[10] Products for the intraday market segment will be introduced and tested in the winter 2020-2021.

Deactivation period	None
Granularity	None
Minimum duration of delivery period	60 minutes
Maximum duration of delivery period	No limit
Validity period	By contract, normally all hours yearly or all hours between November and March or defined hours between November and March
Mode of activation	Manual by FSP, API or text message and e-mail notification
Availability price	Differs depending on type of contract and resource type
Activation price	Fixed price (according to contract)
Divisibility	Yes
Location	Yes
Recovery period	No
Aggregation allowed	Yes
Product Symmetry	No, only up-regulation (load reduction)
Verification cleared bid	Data from real-time metering received from EDIEL[11]. FSP resource time-series is compared to baseline (for aggregated resources and batteries verification mean is under further investigation).

5.2.3.2. Congestion management free bids

The congestion management free bids consist of available flexibility of generation and load. This flexibility is offered day-ahead by FSPs for congestion management purposes. Table 8 shows the attributes of the congestion management free bids, which is obtained from CoordiNet D4.1 (not published yet). Relevant information is also available in [32].

Table 8: Attributes of congestion management free bids product

Attribute	Value
Preparation period	Day-Ahead: Bids submitted 9:30 day before. Information of cleared bid after 10:30 the day before delivery Intraday: clearing two hours before delivery time
Availability	Availability as bid
Ramping period	None
Full activation time	None
Minimum quantity	1 MW (for innovation lower)
Maximum quantity	Not defined
Deactivation period	None
Granularity	0.1 MW
Minimum duration of delivery period	60 minutes
Maximum duration of delivery period	According to cleared bids day before (may bid up to 24 hours per day)
Validity period	Not defined

[11] EDIEL is a format required to be used for electronic communication between network owners in Swedish metering regulation.

Mode of activation	Manual by FSP, API or text message and e-mail notification
Availability price	No[12]
Activation price	To be defined. Pay-as-cleared winter 2019/2020 (all FSP receive price of highest accepted bid)
Divisibility	Yes
Location	Yes
Recovery period	No requirements set (FSP may configure recovery period in market platform)
Aggregation allowed	Yes
Product Symmetry	No, only up-regulation (load reduction)
Verification cleared bid	Different methods under evaluation

5.2.3.3. Congestion management peer-to-peer products

The peer-to-peer market, enables, in a distributed manner, the trading of capacity between producers and consumers for managing limited grid capacity which could arise, e.g., during planned maintenance. Table 9 shows the product attributes of the peer-to-peer product (the focus of SE-1b BUC).

Table 9: Attributes of free bids peer-to-peer product.

Attribute	Value
Preparation period	Continuous market with deadline for bids
Availability	As bid
Ramping period	None
Full activation time	None
Minimum quantity	1 MW (for innovation lower)
Maximum quantity	Not defined
Deactivation period	None
Granularity	None
Minimum duration of delivery period	60 minutes (on average)
Maximum duration of delivery period	As decided between peers (may be as long as maintenance period)
Validity period	During maintenance periods in the DSO or the TSO grid
Mode of activation	Manual by FSP
Availability price	None
Activation price	Pay-as-bid
Divisibility	Yes
Location	Yes
Recovery period	Not defined
Aggregation allowed	Yes
Product Symmetry	Gotland: Up-regulation (production increase) peered with Down-regulation (load increase) Västernorrland and Jämtland: Up-regulation (production increase) peered with Down-regulation from another production unit (production-decrease)
Verification cleared bid	Under evaluation

[12] Compensation for availability can be received by reserved bid. See section 5.3

5.3. Congestion management in the Greek Demonstrator

The Greek GR-2a and GR-2b demonstration campaign focuses on congestion management reserved products (BUCs in GR-1 demonstration campaign are related to voltage control). The same products will be tested in both BUCs considering different coordination schemes.

Market service
The main focus of BUCs GR-2a and GR-2b is **congestion management**. A local DSO market will be implemented to procure the flexibility. The purpose of the market would be the engagement of the necessary capacity and the appropriate decrease or increase of energy to eliminate congestions.

<table>
<tr><th>Market participants</th></tr>
<tr><td>For the DSO local market, the actors are as follows:

Market Operator: At the time of writing this report, it has not been decided yet whether the DSO or an independent actor will be the market operator.
FSPs: Small diesel generators, HVAC and water pumps in Kefalonia. Battery Energy Storage System, Households and a small CHP in Mesogia. The FSPs are represented by an aggregator.
DSO (HEDNO): The system operator detects the congestions and asks for flexibility.
TSO (IPTO): Depending on the coordination scheme that is applied the role of the TSO is different (see below).
</td></tr>
</table>

Coordination scheme
The implemented coordination schemes aim at performing congestion management for both the DSO and the TSO via a market-based mechanism. It is in the coordination scheme that the main different lies between 2a and 2b: the implemented coordination schemes are (cf. Deliverable D1.3) the **Multi-Level** (GR-2a) and F**ragmented Market Models** (GR-2b). In the Multi-Level Market Model, the remaining bids whose activation would not lead to distribution system violations are forwarded to the TSO Market. In the Fragmented Market Model, the TSO and DSO decide the energy exchange between them and it should be respected during the activation of flexibility in both systems. In more detail:

- For BUC GR-2a: Multi-level Market Model. In this BUC, based on the Multi-Level Market Model, the FSPs that are connected to DS can provide flexibility to the TSO, after the DSO has assured that their activation will respect the DSO grid constraints. Therefore, TSO can eliminate congestions using flexibility provided by the flexible resources connected to distribution and transmission system.

- For BUC GR-2b: Fragmented Market Model. In this BUC, based on the Fragmented Market Model, DSO and TSO can procure flexibility only from the flexible resources connected to distribution and transmission system, respectively. The flexibility resources connected to DS can be used indirectly for the elimination of voltage violation in TS through the proper power exchange between them.

Market Product

What is cleared includes:

- Upward reserve
- Downward reserve

It includes both

- **Congestion management reserved** (capacity-based product)
- **Congestion management non-reserved** (energy-based product)

Market timing

There are three types of market: day-ahead, intraday and real-time. The markets are either operated by the TSO or by the DSO. The DSO operates day-ahead, intraday and real-time (local) congestion management markets while the TSO operates only a real-time (global) congestion management market. The markets have the following timing characteristics:

- **Market frequency**.
    - Day-ahead: daily
    - Intraday: daily
    - Near real-time: every 15 minutes
- **Market clearing time.**
    - Day-ahead: gates open at 16h D-1 and closes at 23:00 D-1 while results are published at 23:30 D-1.

◦ Intraday: gates open at 5h D and closes at 08:30 D while results are published at 09:00 D. ◦ near real-time: gates open at H-1h and closes at H-15min while results are published at H-5min. • **Market horizon**. ◦ Day-ahead: multiperiod market and will include 24 periods of 1h. ◦ Intraday: multiperiod with a granularity of 1h. ◦ Real-time: single period of 15 minutes.

Market dimensions	
Trading Type	**Portfolio trading** approach. The market is **bilateral** and **symmetric**.
Auction Type	The market is defined by **closed-gate auctions.** The auctions have **independent horizons**.
Centralization level	As detailed in the BUC definition, this local market is **highly centralized** (at a local level).
Market pricing	Pay-as-cleared scheme with one unique uniform price for the full network (no nodal pricing) per period.
Bid types	The market product (bid) is defined using the following format: • **Member** to identify the entity submitting the bid (aggregator or unit). • **Broker Ref.** to identify the unit ID in case an aggregator is submitting the bid. • **Date of Delivery.** • **Service** to describe the service to be offered (FCR, aFRR, mFRR). • **Regulation** (Upward or Downward). • **Power** to define the quantity of the bid in MW. • **Price** to define the energy price in EUR/MWh. • **Location** to define a connection within the grid from which the bidder will dispatch on activation.

Objective type	The objective is to **minimize the cost** of the provided ancillary services (capacity and energy), that are required to eliminate congestions violations, while respecting the grid constraints.
Network representation in the market	Both DSO and TSO grid constraints are considered in this BUC. Nevertheless, these constraints are not included directly in the market auction itself (explicit network constraints discriminating the bids in the clearing) but are taken into account during **prequalification** phase. In this prequalification phase, flow-based tools are used to take into account these grid constraints which include voltage constraints.

6. Analysis of the market designs for congestion management in CoordiNet

6.1. Introduction

Here, an analysis of the market designs for congestion management in the different CoordiNet demonstration campaigns. To this end, we split the evaluation process into a set of criteria, which are goals and features that the markets should have, and a set of dimensions. These dimensions represent indices which could be used to measure (or analyse) whether these criteria are met in the proposed BUC market designs and possible methods of improvement.

The dimensions could be split into dimensions that are evaluated qualitatively and dimensions which require a quantitative/analytical analysis using e.g. proposed toy examples and case analyses.

Each performed analysis is based on the specific way in which a BUC considers the service and coordination scheme. For example, the definition of "congestion" could be considered differently in different BUCs, where one BUC considers constraints over line flows, while another one considers subscription levels between different grid levels as the main congestion management constraints (i.e. capacity for power flow between a lower voltage grid – ran by a local DSO – and a higher voltage grid ran by a regional DSO or TSO, as is the case in, e.g., SE-1a). In addition, a certain coordination scheme could be interpreted differently in different BUCs. For example, a multi-level coordination scheme considers in its original formulation (in Deliverable 1.3 [12]) that the FSPs could modify their bids between the clearing of different market levels. However, certain BUCs (e.g. SE-1a) could consider that the FSPs may not modify their bids, where the markets involved would forward unused bids from one market to its subsequent market.

The assessment criteria and dimensions we use for the market analyses are:

- Market efficiency (with dimensions including service provision, participation/liquidity, opportunity for gaming, market power),
- Coordination (with dimensions including complexity of coordination mechanism, feasibility of the solution, efficient allocation of resources, transparency of the coordination and solution generation, efficient exchange of relevant data),
- Synergy with current and future EU markets (with dimensions including synergy with current markets and synergy with future designs and regulations), and
- Complexity of clearing mechanisms (with dimensions including consideration of network models and type of mathematical formulation). These criteria and dimensions are enumerated next.

A more detailed description of the evaluation criteria and dimensions is presented next

<u>**Criteria:**</u>

1. Market efficiency: does the market lead to a maximization of social welfare and pricing efficiency as well as lead to the fulfilment of the system operators' needs? In other words, does the market mechanism meet the operator's needs at minimum cost, maximize the producers' (FSPs') and consumers' surplus, while creating a fair competitive environment (reduction in market power), high liquidity, low barriers to entry, transparency, and technology neutrality? -> [criterion]
    - Ensuring the provision of the required service: this is related to the need to effectively provide the service (for example, address the congestion identified so that no network constraint is violated)->[dimension/index]

- Efficiency of Service provision assuming no gaming by market participants occurs: here, the efficiency of the scheme is assessed assuming that generators bid the true extra costs they incur in providing the service-> [main dimension/index]
  - Meeting the system operators' needs at minimum cost (is total cost minimized)?
  - Maximization of producers' and consumers' (FSPs) surplus (depending on what the problem objective is)
  - The efficiency of market clearing and renumeration schemes is assessed. Clearing efficiency depends, among other issues, on the consideration, or not, of the relevant constraints within the market clearing process
- Participation and effects on liquidity: -> [dimension/index]
  - Simple participation rules
  - Low barriers to entry/exit
  - Effect of product requirements (granularity, timing, activation duration, etc.)
  - Technology neutrality
  - Product design and requirements:
    - Simple/complex – consideration of units' technical characteristics
    - Divisible/non-divisible
    - Aggregation of resources (permitted vs. non-permitted)
- Opportunities for gaming: -> [dimension/index]
  - In, e.g., coordination schemes with multiple markets
  - In multi-stages of redispatch due to infeasibility, or incentives set for being dispatched in one stage rather than another one
- Market power -> [dimension/index]
  - Opportunities for market power based on aggregators' size (ownership of big portfolio)
  - Forward contracting (long-term contracts)
  - Reserved and free bids
  - Connection to liquidity

2. Coordination -> [criterion]
   - Complexity of solution and coordination mechanism -> [dimension/index]
     - Centralization level required
     - Level of coordination required
       - Number of entities that must coordinate
       - Level of shared information/ communication required
   - Feasibility of solution: Successful prevention of constraint violation -> [dimension/index]
     - A bid cleared in one market does not violate a constraint in another system/market
     - Ability to consider constraints that one bid in one market creates in another market
   - Efficient allocation of resources: in schemes that consider multiple markets, are bids used where they are most efficient or have most value? -> [dimension/index]
   - Transparency of the market clearing process and information sharing -> [dimension/index]
   - Efficient exchange of relevant data -> [dimension/index]
     - Confidentiality: do the shared data lead to revealing any system operators' or FSPs/prosumers sensitive information?
3. Synergy with the current and envisioned future EU energy market designs -> [criterion]
   - Can the proposed market design fit with the current existing markets and future envisioned market designs? -> [dimension/index]
     - Timing:
       - Gate closure time – before/after wholesale; other markets
       - Period length – duration and granularity of delivered product
   - Does it follow the envisioned future modifications to the EU markets landscape (based on proposed recommendations and envisioned regulations)
4. Complexity: -> [dimension/index]
   - Consideration of physical reality (grid constraints) – before/during/after clearing

- Type of clearing problem (e.g. LP, non-linear convex problem, etc.)

The analysis of different market designs in the CoordiNet demonstration campaigns is provided next, based on these set of criteria and dimensions and based on developed illustrative examples and case analyses.

6.2. Market design analysis of ES-1b

6.2.1. Description of the scheme

The congestion management scheme applied in Spain is a redispatch type of scheme, where the infeasibilities resulting from the unconstrained dispatch (day-ahead market) are addressed through a constraint management scheme in a second stage (congestion management market). The objective to be minimized in the unconstrained dispatch is the total system operation costs, as resulting from the bids that are accepted. The objective to be minimized in the network constraint management stage is a combination of the redispatch costs, as resulting from the bids accepted in this second stage, and the total volume of the changes made to the unconstrained dispatch.

The bids submitted to the unconstrained dispatch (first stage) and to the constraint management redispatch (second stage) are separate, independent. As a result of the unconstrained dispatch in the first stage, a unique, common, marginal price is applied to all the generation and load dispatched. Prices in the second stage applied to each bid that is accepted correspond to the level of this bid (pay as bid), except for downward energy bids in the day-ahead market, where the activation price is the day-ahead energy market price. The prices computed in this second stage are only applied to the generation (including consumption from pumping units)[13] units and only for the energy that is re-dispatched, not to the energy dispatched in the first stage.

Aggregation of bids is possible, and the limits in prices are zero as minimum price, while they are not limited as maximum prices.

6.2.1.1. Case Example

To illustrate the Spanish system, the 2-node system in Figure 12 will be used. The system includes nodes N1 and N2, where, for each generator, GX, its variable production cost C_g^x , in monetary units, and its generation capacity, P_g^x, in units of power, are provided, as well as the demand to be served in node N2, P_d. There is a link between both nodes, whose capacity is 1000 units.

[13] Besides pumped hydro consumption, demand side participation is not possible in the current market.

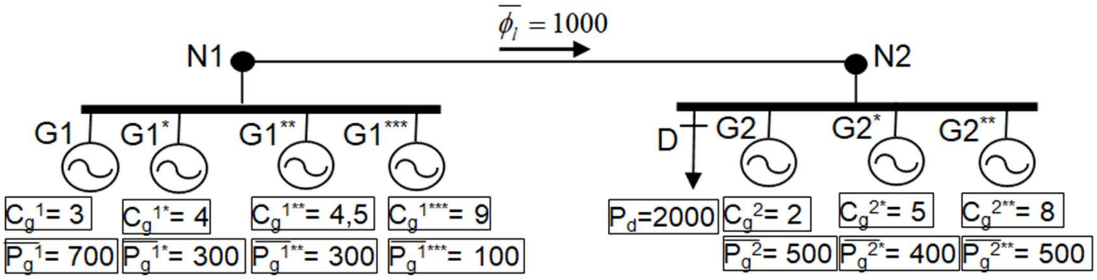


Figure 12: 2-node example illustrating the functioning of the global congestion management scheme in Spain

If generators bid competitively, in the original unconstrained dispatch, the amount of energy that each generator is dispatched follows: P_g^1=700; P_g^{1*}=300; P_g^{1**}=300; P_g^{1***}=0; P_g^2=500; P_g^{2*}=200; and P_g^{2**}=0. Then, the resulting price of the unconstrained dispatch would be P_{unc}=5 (variable production cost of the most expensive unit being dispatched).

Let's assume that the unconstrained market process considered is not the day-ahead one, but, for example, an auction corresponding to the intraday time frame, while the redispatch takes place in real-time to address the existing infeasibilities. Then, separate bids, submitted by the FSPs, are considered for the redispatch stage. Generator G1**, behaving competitively, bids its variables production costs, 4.5 monetary units per unit of energy, for being dispatched downward energy (i.e. the cost this generator could avoid by being exempted from producing energy). Then, assuming that the objective function is just to minimize the resulting costs, generator G1** is constrained off for 300 energy units, receiving a compensation of 0.5 monetary units (difference between the unconstrained market price and the bid submitted by this generator) per unit of energy that is constrained off. Then, the total compensation received by this generator for being constrained off amounts to 150 monetary units. Besides, generators G2*, and G2** are constrained on for 200 and 100 energy units, respectively, thus earning a price of 5 and 8 monetary units, per unit of energy for this energy respectively.

6.2.1.2. Coordination scheme

The coordination scheme to be considered is the one taking place at the global congestion management level. At this level, there is a common market platform for the clearing of the dispatch. Congestion in both TSO and DSO grids is managed by the TSO. In order to solve congestion in the DSO grid, this entity sends information on the constraints to be managed and the resources available for this. Then, the TSO manages all the resources, both those located in the distribution grids and those others located in the transmission grids, and computes, through the central platform, the use to be made of these resources to address congestion at any level.

6.2.2. Case Analysis

6.2.2.1. Market efficiency

6.2.2.1.1. Ensuring the provision of the required service

If there are enough bids to address all the infeasibilities resulting from the unconstrained dispatch, the final dispatch, once the second stage has taken place, should be feasible. Then, congestion in the TSO or DSO grids occurring from the unconstrained dispatch should have been managed, making the flows in all the network assets compatible with the corresponding capacity limits.

6.2.2.1.2. Efficiency of service provision assuming no gaming by market participants

Efficiency of the dispatch: minimization of system costs, or maximization of producers and consumers surplus

If all the generators in the system bid their true production costs, and the management of the congestion on the several existing bottlenecks is coordinated efficiently (an efficiently coordinated redispatch in all these bottlenecks takes place), the final dispatch resulting from the second stage should be close to be most efficient solution. Some efficiency losses may result from the fact that, in the redispatch stage, the total volume of changes to the unconstrained dispatch is minimized together with the cost of the redispatch. In an efficient dispatch, the set of generators, and consumers, being dispatched finally should be those placing the highest economic value on the use of the grid, i.e. those minimizing the system operation cost.

Efficiency of market clearing and remuneration schemes (prices)

Generally speaking, pay-as-bid prices, when agents submit bids reflecting their true variable production costs, do not send efficient pricing signals. According to these prices, the energy delivered in each node is not priced at its opportunity cost for the system. Then, the price paid to the provider of this energy does not reflect the value that this energy has for the system. This results, for example, in the long-term decisions (investment, decommissioning and extension of the useful life of the power plant) made by generators not being the optimal ones from the point of view of the system, which, in turn, results in losses of efficiency for the system.

Of course, under this type of scheme, generators have the incentive not to bid their production costs, but, instead, bid the highest price they believe that could be accepted in the dispatch, thus getting closer to marginal, efficient, prices. However, these agents may not be able to predict accurately the prices bid by others, and, therefore, the marginal value of the energy in the dispatch. Then, efficiency losses may take place. Besides, not bidding their production costs may be deemed an anticompetitive behaviour by regulatory authorities, which may lead the latter to fine these agents.

In addition to inefficiencies associated with pay-as-bid-prices, applying different prices to the unconstrained dispatch from those computed in the redispatch stage is also causing inefficiencies. The energy dispatched in the first stage, the unconstrained dispatch, is not priced at the true marginal value of energy in the dispatch in each of the areas of the system that congestion divides this system into. Besides creating operation problems and losses in the efficiency of the dispatch, as argued below in paragraph 6.2.2.1.4, this creates inefficient long-term signals, misleading the decisions by agents on where to place new generation and load.

Within the unconstrained dispatch, the system price could be artificially depressed sometimes (see case B in paragraph 6.2.2.1.4), when no energy production in the importing areas is dispatched, or artificially increased others (see case C in paragraph 6.2.2.1.4), when some artificially increased bids from cost competitive generators in importing areas are not dispatched in the first stage, i.e. in the unconstrained dispatch.

The artificially modified bids submitted by agents in the redispatch stage, discussed within paragraph 6.2.2.1.4, could result in inefficient pay-as-bid prices, as argued above. However, these prices would only affect the energy corresponding to these bids, and not the rest of energy dispatched in this same bid area, as it happens when artificially modified bids are submitted and marginal prices apply.

6.2.2.1.3. Participation and effects on liquidity

Liquidity problems may occur in importing areas, where, typically, the number of agents being able to solve a congestion may be small. However, this problem may exist under any congestion management scheme. Otherwise, when liquidity problems are small, the set of market rules applied are simple. This fosters participation in the market, since having simple rules in place allows market agents to better understand the market functioning, and more easily predict the market outcome, which also increases their confidence in the market.

There are low barriers to entry in the market for a multiplicity of reasons. First, the aggregation of resources is possible, which facilitates the indirect participation of small agents in the market through aggregators. Besides, the congestion management market is technology-neutral. Renewable generation has been traditionally banned from participating in certain markets based on its capabilities and/or size, but this situation is now avoided, thus avoiding unfairly discriminating against the participation in this market of certain generators or storage devices according to their technologies.

Additionally, it is possible to apply complex rules to define the features of bids. As a result, market agents can set up conditions affecting the clearing of their bids, allowing them to guarantee the recovery of their variable costs, including, among others, start-up costs. These complex bid design rules allow the market agents to reflect in their bids the impact that the corresponding unit's technical characteristics has on its variable costs. Allowing the agents to recover all those costs resulting from their participation in the market should encourage these agents to participate in this market in an open and transparent way. Complex rules that may apply to bids include those affecting the divisibility of bids, which can be defined as divisible or no divisible.

The duration of the activation of bids can be as short as one hour, which also facilitates the participation of those generators and storage devices unable to hold a change in their output for longer periods.

6.2.2.1.4. Opportunities for gaming

The fact that the dispatch is computed in two stages, and that the prices applied in each stage are different, produces perverse incentives for the market agents (i.e. generators) not to bid their true production costs and, instead, artificially modify their bids to increase their market profits. Next, these potential sources of inefficiency are classified into types, termed cases, and briefly described.

Case A: associated with the payment of compensations to constrained-off agents

First of all, the case where compensations are paid to market agents for their foregone market profits resulting from the fact that they are constrained off in the redispatch stage after having been dispatch initially in the first stage is analysed. This occurs when the price of activation of downward energy in the redispatch stage corresponds to the bid price, as in the market from 1 hour before to real-time. Then, the compensation received by an agent being constrained off corresponds to the difference between the day-ahead market price in the unconstrained dispatch (first stage) and the downward energy bid by this agent accepted in the redispatch stage. In this case, those generators not being cost competitive in the unconstrained dispatch may be tempted to game the scheme in their own benefit. These generators could submit a bid below their production costs to the unconstrained dispatch, in order to be dispatched then. Afterwards, they would request a low compensation (bid a high level of payment for downward energy) in the redispatch stage in order to be constrained for the same amount of energy they have been dispatched previously in the first stage. Then, they would be left without energy to eventually produce while earning, in net terms, an amount per unit of energy initially dispatched equal to the compensation requested for being constrained off. In order for these generators to make sure that they are constrained off in the redispatch stage, they would have to bid a price for downward energy very close to the market price in the unconstrained dispatch, i.e. they would have to request a very low compensation. These generators could fail to accurately predict the minimum price they should bid for downward energy in the redispatch stage, and, then, ask for a too high compensation for being constrained off. In this case, they would not be constrained off. They would be part of the final dispatch, despite not being cost competitive, thus making a loss in the market, and increasing the operation cost of the system, which would reduce the efficiency of the final dispatch.

As an example, the 2-node system depicted Figure 12 will be used. Generator $G1^{***}$ could bid below its production costs, for example, a price of 4.9 monetary units per unit of energy, in the unconstrained dispatch in order to be initially dispatched. Then, the amounts of energy generators in the system are dispatched in the first stage follow: P_g^1=700; P_g^{1*}=300; P_g^{1**}=300; P_g^{1***}=100; P_g^2=500; P_g^{2*}=100; and P_g^{2**}=0. The price of the unconstrained dispatch would remain at 5 monetary units per unit of energy. Afterwards, in the redispatch stage, generator $G1^{***}$ could bid a price of 4.9 monetary units per unit of downward energy, which is consistent with the bid submitted by this generator in the first stage. Then, if this bid is accepted, as expected if the rest of generators bid competitively, generator $G1^{***}$ would be constrained off for 100 units of energy, being left without the need to produce any amount of energy, and making a net profit of 0.1 monetary units per unit of energy that it is constrained off. Then, its net profit would amount to 10 monetary units, while $G1^{***}$ should have never been dispatched, since it is not cost competitive in the unconstrained dispatch according to its true production cost.

Case B: potential inefficiencies in exporting areas

Generators which are close to be marginal in exporting areas and which have been dispatched originally, in the unconstrained dispatch may bid their downward energy at a very low price in the redispatch stage (offering a very low payment, i.e. asking for a very high compensation, for being constrained off). Their aim is avoiding being constrained off in the redispatch. This makes economic sense for them because, if they are not constrained off, they would be earning the unconstrained market price, which is attractive to them (higher than their production costs). As a result of this, instead of constraining off the most expensive generation in exporting areas, cheaper generation, having bid their downward energy at a higher price than the former, could be the one left out of the final dispatch. The latter generators, being aware of the strategy of the former, could also bid below their costs. But this could lead to a situation where constrained off generation is selected based on artificially modified bids by generators, which would probably result in higher operation costs than necessary, i.e. in a decrease of the efficiency of the final dispatch.

It is also true that market monitoring by authorities could largely prevent this gaming strategy from being successfully implemented by agents. Market agents having offered their energy at a much higher price in the first stage than in the second (having bid high in the unconstrained dispatch and having offered a much lower price for downward energy in the redispatch stage) could be spotted as being suspicious of trying to game the system and could be investigated in depth. This could deter agents from adopting the aforementioned strategy.

Considering again the 2-node system in Figure 12, in the exporting node N1, fierce competition takes place among generators to be dispatched, except for $G1^{***}$, since the price in the unconstrained dispatch (5 monetary units per unit of energy) is quite attractive for them. Then, generator $G1^{**}$ in node N1 should bid aggressively below costs, since, otherwise, he would be constrained-off in the redispatch stage. $G1^{**}$ aims to bid below G1 and $G1^{*}$ costs (i.e. 2 monetary units per unit of energy). Then, G1 and $G1^{*}$ could follow the same strategy, bidding below their costs, in order not to be left out of the final dispatch. Due to this process, the final dispatch in N1 may not be efficient, since $G1^{**}$ may replace G1 or $G1^{*}$, while producing energy at a higher cost.

Case C: potential inefficiencies in importing areas

Within importing areas (load pockets), the production of energy needs to be increased in the redispatch stage with respect to that dispatched in the unconstrained dispatch. The generators in these areas have the perverse incentive to artificially increase their bids in order not to be dispatched in the first stage, where they would be paid the unconstrained market price for their energy, and, instead, be dispatched in the second stage, when competing only with generation in their load pocket, and the marginal upward energy bids accepted are higher. As a result of this, the redispatch computed may be inefficient, since it would be based on artificially high bids. What is more, there may be situations where, contrary to what the market agents assume will happen, there is no need for the redispatch to take place because the original, unconstrained, dispatch turns out to be feasible, i.e. no line is congested in the network when implementing this dispatch. Then, generators in importing areas that are cost competitive, but have bid artificially high prices, would be left out of the dispatch. Note that some of these generators may be very cheap (may have very low production costs), while other generators being dispatched are much more expensive.

Going back to Figure 12, within the importing area, N2, inframarginal generators have an incentive to bid a price close to the marginal bid accepted in the redispatch stage (8 monetary units per unit of energy, corresponding to generator $G2^{**}$). Then, G2 and $G2^{*}$ become less competitive than most generators in node N1. If energy from G2 and $G2^{*}$ is required to cover demand, even when all the generation in N1 comes first in the merit order list, the price of the unconstrained dispatch may increase substantially, up to almost 8 monetary units per unit of energy. Then, the generators' revenues increase substantially at the expense of consumers.

On the other hand, if the demand in the system is lower than that depicted in the figure, and expected (i.e. Pd =1000), then no redispatch would take place. The second stage in the congestion management process would not be needed. Consequently, having bid artificially high prices, generators G2 and $G2^{*}$ could be left out of the dispatch, even if G2 is the most cost-competitive one. Generators G2 and $G2^{*}$ run a risk associated with their ability to predict system conditions, regarding, for example, the level of demand.

Case D: inefficiencies associated with the pay as bid rule applied in the redispatch stage

Not only different prices applied to different stages in the congestion management process, but also pay-as-bid rules, encourage generators to artificially modify their bids to get access to the most favourable price possible. They have the incentive to issue a bid that is as close as possible to the one to be marginally accepted, but lower, in the case of upward energy, when they aim to be constrained on, and higher, in the case of downward energy, when they aim to be constrained off. However, they may fail in predicting the marginal bid accurately enough, or bid too aggressively, and be left out of the final dispatch, not being constrained on, even when they are cheaper than other generators that are dispatched, or be left within the final dispatch, not being constrained off, even when they are more expensive than some generators whose energy has not been dispatched. In the former case, generators having issued artificially modified bids and not being constrained on would not be making a profit in the market, even when they could have made it if bidding competitively. In the latter case, the generators trying to game the system would be selling their energy at a price lower than their production cost, thus making a loss. In both cases, there would be a loss of efficiency of the final dispatch with respect to the optimal one.

6.2.2.1.5. Market power

As mentioned above, the lack of liquidity within some generation bottlenecks, where all, or most of the units able to ease a constraint violation may be owned by the same company, may result in large market power being held by this company in the constraint management market. Aggregation, which is possible within the Spanish market, could also result in a dominant position by the aggregator in the local constraint management market, which should be prevented. However, the fact that the prices applied in the redispatch stage are pay-as-bid ones and that they only affect the re-dispatched generation significantly reduces the amount of generation within the company that would earn artificially increased prices. This significantly reduces the incentives to exercise market power. Forward contracting is possible within the Spanish market, which may also help reducing the exercise market power.

6.2.2.2. Coordination

6.2.2.2.1. Complexity of solution and coordination mechanism

This mechanism requires centralizing certain activities in the TSO, which requires DSOs to agree to let these activities in the hand of the former. This is a factor that may increase resistance to the implementation of this scheme. The level of centralization of this scheme is high.

Besides, some relevant amount of information needs to be exchanged between the DSOs and the TSO. This exchange of information may entail some complexity.

On the other hand, there is large experience on the implementation of redispatch type of schemes, even when the scheme applied in Spain has may have some specificities which make it unique.

6.2.2.2.2. Feasibility of solution: Successful prevention of constraint violation

Coordination inefficiencies, leading to potential violation of constraints, may occur when congestion in several network bottlenecks, either within the same grid or in several (TSO and DSO) ones, is not managed in a coordinated way. Given that, under this scheme, all the congestions are managed in a common market platform (based on information submitted by the DSO, in the case of the congestion in the grid of the latter), the room for achieving a coordinated solution not violating any constraints is larger than under those other schemes where congestion in the TSO and the DSO grids is managed by different entities.

6.2.2.2.3. Efficient allocation of resources

The fact that different prices apply to the unconstrained and redispatch stages of the congestion management process may lead market agents not to bid in the market where they should, or, analogously, to submit artificially modified bids to the market at one stage in order not to be dispatched at this stage, even when being dispatched at this stage would be most efficient (see the gaming incentives discussed above). This could lead to (coordination) inefficiencies in the dispatch.

On the other hand, being all the bids and constraints managed centrally in the same platform, there is no option to choose whether to bid in the TSO or DSO constraint market, since these are unified. This prevents agents from choosing wrong, in efficiency terms, the market, between these two, where they should place their bid. Both the TSO and the DSO constraints are managed within a central market in the same platform.

6.2.2.2.4. Transparency of the market clearing process and information sharing

All the bids are centrally managed within the same platform and are dispatched according to a previously defined algorithm. There is transparency regarding the clearing algorithm to apply, which is minimizing jointly operation costs (as computed based on the submitted offers) and the overall volume of changes made to the unconstrained dispatch. However, the clearing process could turn out to be complex. Some of the active network constraints to manage may be interdependent, though this may not be frequent. Besides, the clearing is also affected by those factors reflecting the sensitivity of the flows on the congested elements with respect to power injections or withdrawals by FSP. Consequently, in some specific situations, the outcome of the dispatch may be difficult to understand by market agents.

The information to be submitted by the market agents includes the type of offer (production, consumption, or import), the amount of energy they are offering, the time period that the offer refers to, and the price offered. The location of the generation or storage facilities to be mobilized for each offer need to be considered as well within the clearing process, since the location of resources that are mobilized conditions the aforementioned sensitivity factors. In the case of thermal generators, complex bids are accepted. In this case, start-up costs are also sent. Thus, there is transparency about the type of information to be shared by FSP with the central platform.

6.2.2.2.5. Efficient exchange of relevant data

The type of information to be shared by FSP is the customary one (location, amount of energy and price offered). This information should be publishable. Obviously, for congestion management purposes, specifying the location of resources participating in the process is required, since this information is needed to determine the unit contribution of agents to the flow over the congested grid assets.

6.2.2.3. Synergy with the current and envisioned future EU energy market designs

The features of the product traded in this congestion management market is in line with the recent developments within markets in Europe. Thus, congestion management energy within the Spanish system is delivered in time periods of 1 hour, both in the day-ahead and in the real-time market. Closure times are also in line with common practice in the markets of this type. Besides, clearing centrally the congestion management bids corresponding to all the active constraints results in an implicit coordination of the management of congestion in all the affected assets. This is also in line with the latest development at European level.

However, the pricing mechanism applied does not fully comply with the guidelines set at European level when addressing systematic congestion. The system price resulting from the unconstrained dispatch computed in the first stage of the congestion management process, which is eventually applied to all the energy but to the re-dispatched one, does not reflect the congestion existing in the grid, since this price is computed neglecting the grid congestion. Therefore, this price, does not reflect real supply conditions in each area of the system, as energy prices should. This may be deemed acceptable when grid congestion only occurs sporadically and does not affect the bulk transmission system, but very specific areas, or pockets.

6.2.2.4. Complexity

As mentioned, grid constraints are not taken into account when computing the system price applied to most of the energy transacted by the generation and storage in the system. This largely simplifies the matching algorithm. However, it also leads to inefficient prices setting perverse incentives for agents.

The clearing algorithm cannot be linear, or simple, due to the need to deal with complex constraints affecting the bids that are submitted by thermal generation. Otherwise, for regular, simple, bids, the clearing algorithm could be linear.

6.2.3. Possible improvements to the congestion management scheme

Most of the inefficiencies of the congestion management scheme applied in Spain at global level could be avoided by computing marginal prices specific to each bidding area, based on the results of the redispatch stage (second phase, or redispatch), that were applied both to the energy dispatched in the first stage (unconstrained dispatch) and in this second stage. However, this would be tantamount to applying a zonal/nodal pricing scheme, even when the zonal/nodal prices are computed in two stages, instead of just only one. Applying these zonal/nodal prices would render the first stage useless in practice. However, even this zonal/nodal pricing scheme would have some weak points, since it could create some inefficiencies that are specific to it. Thus, applying nodal/zonal prices in importing areas, in the presence of market power in these areas (which is very common in the constraint management market), would result in extra incentives for the agent(s) with market power to exercise it, since the market profits this agent would obtain from the exercise of market power would be significantly larger than under a pay-as-bid pricing scheme. What is more, the price distortion created by the exercise of market power by these agents would be larger than under a pay-as-bid pricing scheme.

Computing marginal prices in the redispatch stage (second stage) that are only applied to the energy re-dispatched (constrained-on in the redispatch stage), would solve those inefficiencies of the mechanism currently applied that are specific to the application of pay-as-bid prices. However, this would not avoid those other inefficiencies that are caused by the application of different prices to the two different stages of the congestion management mechanism, which are the majority of the inefficiencies discussed above. Besides, the application of marginal prices in the importing areas to the energy re-dispatched in these areas could exacerbate the exercise of market power in these areas, as well as its consequences, as it hast just been argued.

Lastly, some other additional measures can be applied, which could be taken to improve the functioning of the congestion management scheme, even if this is left unchanged. First, publishing the outcome of the first and second stage of the congestion management process, including the identity of the locations affected by active constraints (typically, grid pockets in the Spanish system) would increase the level of awareness of the market agents about the supply conditions affecting these locations. This could foster the participation of extra generation and storage resources in the congestion management process, which could ease the network congestion and partially reduce the level of intensity of the perverse incentives driving other agents no to bid competitively within this process. Apart from this, allowing demand to participate in the congestion management process, mobilizing demand response resources, should also increase the level of competition, and partially ease congestion, and counteract some perverse incentives of the agents involved in the process, by decreasing the level of intensity of these incentives. However, neither the publication of additional information about the congestion management output, nor the participation of demand in this process, would avoid perverse incentives. This could only be achieved through the modification of the rules applying to congestion management, as discussed in the first two paragraphs of this subsection.

6.3. Market design analysis of SE-1a

6.3.1. Introduction to the analysis

In this subsection, an analysis of the market design developed and used in the SE-1a BUC is provided. This analysis follows a set of criteria, highlighting the different goals of the market, and different dimensions, which are indicators/indices to analyse and assess the fulfilment of the different criteria. In addition, a case analysis is developed to assess two specific elements of the SE-1a market design: 1) the use of a multi-level market model, as compared to a common market model (giving priority to the local DSO to access local flexibility before this flexibility is made available to the regional DSO) and its possible effects on the economic efficiency of the market, and 2) the use of static impact factors (which quantify the effect of the activation of a certain flexibility in the system on the alleviation of the constraint(s) on which the market focuses) and the sensitivity of the market outcomes to these impact factors, affecting the DSOs' costs and FSPs' revenues and highlighting the need for an transparent and accurate calculation of the impact factors.

We note that the congestion management market in the Swedish demonstrator considers a day-ahead market (starting in the demo run 1) and an intraday market (starting in the demo run 2) for flexibility trading. This analysis, focuses on the first stage of the demonstration campaign, which has considered the day-ahead market operation, as the information that is available at the time of writing this deliverable (through D4.4 [2] and D4.5 [22]) primarily encompasses demo run 1 (running during winter 2019/2020).

6.3.2. Description

The goal of the market is to use flexibility resources, located on the local and regional DSO levels, to prevent the power flow between, respectively, the regional and local DSOs and the TSO and regional DSO, from surpassing a pre-set value known as the subscription level (the focus could be at a certain connection point between two levels of the grid, or a collection of connection points). Surpassing this subscription level would require the purchasing of costly additional temporary capacity, if possible, or could be physically prohibited all together; hence, the need for flexibility.

The market is organized into two market sessions (as shown in Figure 13): the local flexibility market and the regional flexibility market. FSPs submit their upregulation bids to the market platform, which first clears the local DSO market and, then, forwards unused bids to the regional DSO market clearing, which is cleared 30 minutes afterwards.

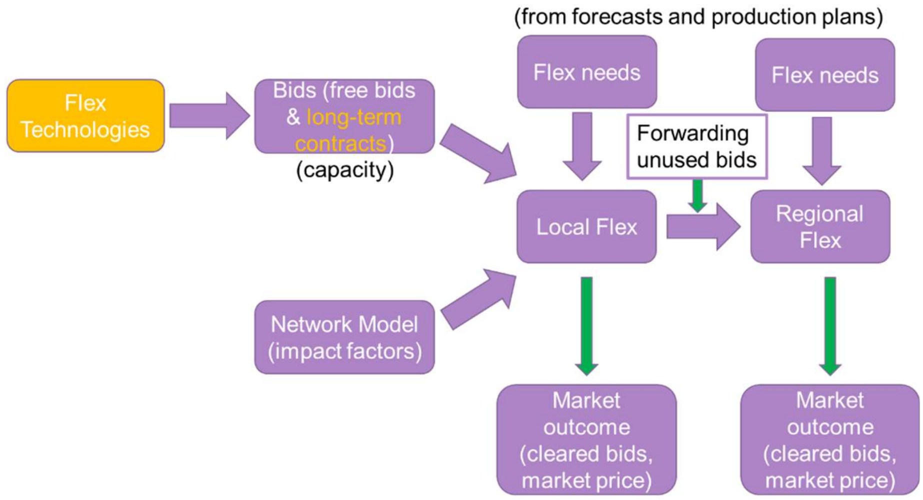


Figure 13: Market Structure and Elements

Each bid is associated with an impact factor, with respect to a connection point, that is between 0 and 1. If the impact factor of an FSP is denoted by x, then an activation of 1MW of flexibility by this FSP will lead to a reduction of $x \leq 1$ MWs at a particular connection point between one layer of the grid and the other.

Offers submitted to the market consist of simple bids (volume/price pairs) with minimum bid acceptance levels and multi-period block orders. Previously contracted capacity through bilateral agreements known as "long-term bids" between the operator and flexibility providers, as well as free capacity bids, are taken into account in the clearing of the multi-level market. As a result of the clearing, offers may be accepted in full or in part (i.e. bid divisibility is allowed). In addition, offers may aggregate flexibility from different units.

Hence, all bids used in the market are capacity bids. Two types of Long-term contracts are used: 1) a reserve type with controllable power level, and 2) conditional connection agreements comprising disconnectable loads. The long-term contracts participate in the flexibility markets using bids with adjusted prices. In other words, during the CoordiNet market session, each of these long-term contracts will be associated with a certain bid price. This bid price will be, hence, compared with the prices submitted by “free capacity bids” to form a merit order list used for the clearing of the market. As the purchased bids are capacity bids, the FSPs are remunerated upon activation.

6.3.3. Coordination scheme

The market follows a multi-level market model scheme that combines features from the common market model and the multi-level market model defined in CoordiNet D1.3 [12]. The coordination scheme includes, first, a local DSO level flexibility market, to which all bids are submitted. After clearing of this market (for resolving subscription capacity considerations between the local and regional DSO), the unused bids (i.e. uncleared bids) are transferred to the regional DSO flexibility market for resolving subscription capacity considerations between the regional DSO and TSO. Hence, through this market model, congestion management is first tackled at the local DSO level. If remaining bids are available, the regional DSO uses them, in addition to bids submitted by resources connected to the regional DSO level, to manage the interconnection with the TSO. This coordination scheme differs from the multi-level market model defined in D1.3 by the fact that the FSPs do not have the ability to modify their bids between the two market sessions. In addition, this coordination scheme differs from the common market model defined in D1.3 by the fact that the scheme gives priority to the local DSO to use available local flexibility for resolving its subscription needs, while only the unused bids are passed on to the regional DSO for possible clearing.

6.3.4. Analysis following the defined set of criteria

As previously stated, the following analysis focuses on the first stage of the Swedish demonstration campaign (i.e. demo run 1, testing the day-ahead market only and running during the winter 2019/2020).

6.3.4.1. Market efficiency

6.3.4.1.1. Ensuring the provision of the required service

The approach provides flexibility provision, so that network constraints (constituting the constrain on the interface power capacity between the grid levels) are respected, provided that enough bids are made available to the different stages (considering free capacity bids and long-term bids). The consideration of free capacity bids and long-term bids (the latter encompassing operational reserves and conditional connection agreements which are also included in the market clearing) increases the pool of flexibility offers, enabling the provision of the congestion management needs by the local and regional DSOs. In terms of efficiency, in the preliminary market phases, long-term bids can increase market efficiency by increasing its liquidity (these bids typically have high bid prices and would not be cleared unless not enough free capacity bids are present and when an increase in the subscription level is not allowed). However, when the market matures, achieving constantly high liquidity, the value of long-term contracts would decrease. In that case, discontinuing these contracts would lead to savings on availability payments made by the DSOs. For more details on the liquidity question, see Deliverable D4.5 [22].

6.3.4.1.2. Efficiency of service provision

The approach allows for the relevant DSO at each stage to manage the capacity connecting it to a higher grid level at a cost dependent on the submitted bids to the flexibility market. In this regard, the automatically generated merit order list considers the prices of the submitted bids, as well as the impact factors of the assets fulfilling the bid. As such, the clearing process takes into account those impact factors (which reflect grid locational information), which supports the efficiency of the clearing mechanism. The calculation of these impact factors is done during the planning phase by the DSO. Hence, the impact factors are static, which may not capture the dynamically changing state of the grid, leading to a possible loss in efficiency/accuracy. Indeed, as shown in the case analysis in subsection 6.3.5, the outcomes of the market is highly sensitive to the impact factors, affecting the total costs incurred by the DSO, as well as the revenues of the FSPs. Hence, an accurate and transparent calculation of these impact factor is paramount to ensure market efficiency, fairness, and transparency.

By giving the local DSO priority in accessing the flexibility bids over the regional DSO, this can lead to a suboptimal solution as compared to a common market model, as shown in the case analysis in subsection 6.3.5. Indeed, a common market can lead to a decrease in the cumulative cost of congestion management in the two markets by allowing the flexibility to be used in the location where it is most efficient. In fact, as highlighted in the examples of the case study in subsection 6.3.5, allowing a minimum acceptance level to be imposed by each bid (i.e. through a minimum bid size requirement which could be adjusted by the FSP), can make this drop in efficiency of the multi-level market more pronounced. On the other hand, these minimum bid level sizes could be essential for the participation of certain FSPs, as they help capture the FSPs technological requirements. In addition, the absence of the possibility for the FSPs to adjust bids between the two market sessions, even though it may decrease the opportunity for gaming (as will be discussed shortly), may result in a decrease in efficiency. Indeed, the ability to adjust bids between the two market sessions would allow each FSP to update its offering strategy to the second level of the market (i.e. the regional market), based on the outcomes of the first level of the market (i.e. the local market). This can introduce opportunities for the FSPs to enhance their revenues, increasing participation levels, which would have a positive effect on market liquidity and efficiency.

An additional component to be highlighted is that the implemented market mechanism solely takes into consideration the subscription levels between the grids as the source of possible congestions. In other words, the goal of the market is to solely manage the flows between grid levels to avoid surpassing the predefined subscription levels. Hence, line flow constraints within each grid and voltage flow constraints are not considered as part of the market (even though they could be considered during the planning/pre-qualification phase). Hence, from a mere market perspective, the generated solution, even though it meets the requirement on the interface power flow between the different grid levels, does not guarantee that all other operational requirements are met (e.g., line flow limits, nodal voltage limits, etc.). Hence, these operational requirements should be addressed either through a pre-qualification phase, through the market itself, or through following corrective actions (i.e. re-dispatch).

6.3.4.1.3. Participation and effects on liquidity

The submission of bids to the platform is relatively simple for FSPs, which can encourage participation. The sequential clearing (multi-stage clearing) without bid re-adjustment allows for the regional DSO to reduce uncertainty in the second stage. In addition, this scheme makes it simpler for FSPs and for the DSOs to run the market, as the FSPs (which could, in a general case, be mainly composed of aggregators relying on inputs and agreements with local DG owners and active consumers) do not need to go over the effort of re-adjusting their bids, while the operators have a constantly clear picture of which bids are available and could be activated (long-term and free capacity bids). Allowing divisible bids and the indication of minimum bid acceptance levels also improve liquidity, the latter of which helps capturing technological requirements of certain FSPs, hence encouraging their participation. Participation and liquidity are also enhanced by allowing aggregation of resources. In addition, the possibility for the FSPs to (automatically) forward their bids to an intraday flexibility trading session and prequalified bids to the Nordic mFRR market (both of which are planned for the second run of the demonstration campaign in winter 2020/2021) can improve the liquidity of the market by giving additional opportunities for the FSPs to gain value from their flexibility.

On the other hand, the use of static impact factors can have a negative effect on the overall market liquidity. The reason is that the FSPs do not have control over these impact factors (as they are a result of the grid connection and location of the flexible assets within the grid). Hence, these impact factors could be perceived by the FSPs as unfair and could discourage participation. To account for this drawback, a clear and accurate computation of these impact factors and a transparent communication of the methodology and results of this computation to the FSPs are needed. Indeed, the use of the impact factors is indispensable to quantify the effects of activation of flexibility on the constraints to be resolved and, hence, it is essential for the effective provision of the needed flexibility. However, a transparent communication of these concepts with the FSPs would provide the FSPs with clarity regarding this process. In addition, liquidity problems may, in general, arise from the market structure of a market with such a scope, i.e. a limited number of participants may be able to provide an efficient solution (including only the subset of participants who can have an impact on alleviating the constraint). An example of this setting is e.g. in the Upplands Energi’s local market, which includes one flexibility resource (namely, an aggregator), as shown in Table 2 of CoordiNet D4.5 [22]. This could, hence, lead to low liquidity levels in practice. This, however, is an inherent characteristic of the grid, as limited flexible capacity could be available at every local level, and not a cause by the market itself.

6.3.4.1.4. Opportunities for gaming

FSPs can bid to the entire multi-level market and their bids are used in the two stages of the market (i.e. first, in the local flexibility market stage and, then, in the regional flexibility market stage). Not allowing bid adjustments in the second stage (i.e. regional market stage) of the market prevents bidders from submitting simultaneous bids (i.e. using the same capacity assets) in two different markets concurrently. In the absence of that criteria, a FSP bidding (intersecting portions of) the same capacity on two different markets will be at a short position in case its combined nomination from these two markets exceeds its delivering capacity. This would create inefficiencies in the clearing (due to the need for re-dispatching measures) and increase the uncertainty for the DSO on the amount of flexibility that can be activated. In addition, by preventing bids to be modified between the two market sessions, a strategic bidder would not be able to influence the result of the first market for potentially leveraging this result in a subsequent market. However, this reduction in gaming opportunities may result in suboptimality of the overall clearing process, as FSPs, if given the opportunity, may be able to adapt their bids to the grid in need to optimize their positions, resulting in the delivery of improved levels of service to the DSOs.

6.3.4.1.5. Market power

Due to the possible inherently low liquidity in some local and regional markets, some actors have the opportunity to exercise a level of market power (e.g., by bidding at higher prices in the absence of possible competitors). However, this is mitigated due to the alternatives that the DSOs have, including long-term capacity contracts and the possibility of purchasing additional subscription capacity, both of which could act as price caps. Hence, expensive bids would not be cleared unless there is a capacity shortage (e.g. in the absence of the possibility of increasing the subscription levels and in the case of shortage of disconnectable loads, typically available through long-term contracts).

6.3.4.2. Coordination:

6.3.4.2.1. Complexity of solution and coordination mechanism

The market is centralized at each stage and is run by either the local or regional DSO (namely, the market operator is the regional DSO in Uppland and Skåne and the local DSO in Gotland). Due to the nature of the procured service, i.e. the decrease of load (through the purchasing of upward flexibility) at each of the grid levels, bid clearing does not necessarily require a high level of information exchange between relevant system operators. This is due to the fact that the activation of flexibility by the regional DSO would not cause congestion problems on the local level, even when local resources are used (as only the subscription levels are considered, and both operators aim at reducing the peak consumption with the upper level). However, information of the local market clearing could be used by the regional DSO to adjust the amount of flexibility it needs to purchased, as a reduction in total load on the local level results in a decrease of the total load of the regional grid, hence impacting the amount of flexibility it must purchase to avoid surpassing its subscription level with the transmission system. This later point is highlighted in the case analysis in subsubsection 6.3.5.1. It is important to remind that these (possibly limited) needs for the exchange of information are specific to the implemented markets in the SE-1a BUC, which aims at solely reducing the flows at connection points between grid levels. In fact, if other congestion management constraints were considered (such as line flow constraints at different distribution lines and voltage magnitude constraints at different distribution buses), coordination between the DSOs would be indispensable to guarantee that the activation of flexibility by one operator does not lead to operational constraint violation in another grid level (even if these constraints are not explicitly part of the market clearing process). In that case, if, for example, the flexibility is contracted on the regional market (second stage) the local and the regional DSO would need to agree on the terms for the provision of the flexibility.

6.3.4.2.2. Feasibility of solution

The clearing process takes into account the impact factors of the different flexibility assets. The DSO uses the impact factors for the calculation of the merit order list. This enables the market clearing results to meet the physical flexibility needs (identified using a load prognosis and additional analysis and adjustments by the DSO) to alleviate the grid constraint in question (i.e. the interface at connection points between the local DSO and regional DSO and between the regional DSO and TSO). As the market solely aims at reducing the interface power flow, special attention is required regarding other operational constraints which can be addressed, e.g. during the pre-qualification phase and through post-market clearing corrective actions, if these constraints have not been accounted for in the flexibility market.

6.3.4.2.3. Efficient allocation of resources

From the received bids, a merit order list is automatically generated, which the DSO then clears manually. This manual clearing is adopted to allow for adjustment in flexibility needs (due to e.g. adjusted forecasts and estimated load levels). However, this can lead to a decrease in perceived transparency by the market participants. The merit-order-based clearing leads to the purchasing of the cheapest flexibility resources to meet the intended system needs, which increases the efficiency of the allocation process. However, the priority given to the local DSO in the coordination scheme can result in the purchasing of bids which would not have otherwise been purchased in a common market model (i.e. without the priority given to the local DSO), leading to a higher level of purchased flexibility than needed and, hence, to higher costs for the DSOs, thus resulting in a lower market efficiency. This comparison is performed in the case analysis in subsection 6.3.5, identifying and quantifying (based on a quantitative setting) this possible drop in efficiency. In addition, as showcased in the case analysis in subsection 6.3.5, the market outcomes and total costs (hence, the market efficiency) is highly sensitive to the defined impact factors. These impact factors have been computed in the prequalification phase of the Swedish demonstration campaign and are thus used as static values. A dynamic adjustment of these values, to capture the dynamically changing state of the system, could therefore lead to a higher market efficiency.

6.3.4.3. Synergy with the current and envisioned future EU energy market designs

The proposed market and product design is chosen in such a way that it answers to the needs of the local and regional DSOs to handle congestions, while also considering synergies with the mFRR market, as unused flexibility bids will be forwarded to the existing mFRR market. There are no general accepted guidelines yet on European level for product and market design for flexibility markets on DSO level. Therefore, the alignment of the proposed product and market design with the (future) Swedish and European (balancing) market will be mainly assessed.

The selected time granularity for the congestion management product (60 minutes) is aligned with the current practice in Sweden, as it corresponds to the imbalance settlement period and the market time unit of the mFRR, the day-ahead and intraday wholesale markets in Sweden. When looking at the future European markets, the target is to move to an imbalance settlement period and market time units of 15 minutes. In that sense, Sweden will also move to a 15-minute imbalance settlement period and market time unit in the intraday and mFRR markets in the future (planned for 2023) [33], as part of the plan to connect to the common European mFRR platform, MARI.

Within the Swedish demonstrator, the minimum allowed bid size in the local and regional congestion market is set at 0.1 MW to enable smaller FSPs to enter the market, while the minimum bid size within the mFRR is assumed to be 1 MW for demonstration purposes. The latter is already considerable lower than the current minimum bid size of 5 or 10 MW (depending on the market zone) in the Nordic mFRR market, but this does align with the future target of the European mFRR market, and thus also the future Swedish target [34].

Market clearing on the CoordiNet congestion management market is still done manually (after the automatic generation of the recommended optimal bids to be cleared by the market platform). In addition, after the local and regional DSOs have chosen bids on the CoordiNet platform, the FSP is contacted by email of bid acceptance or rejection. The communication between FSPs and the TSO in the current Swedish mFRR market is also largely done by phone or electronically, but this process will be automated further in the coming years to meet the Electricity Balancing Guideline requirements. It could therefore be worthwhile to also look into further automation opportunities in the market clearing and the communication process between the DSO and the FSPs with the CoordiNet platform to make the market solution more scalable.

Overall, the proposed design of the local and regional congestion market is quite aligned with the current Swedish market settings. It would be, however, worthwhile to evolve in line with the already planned changes within the Nordic balancing market to meet the overall EU guidelines.

6.3.4.4. Complexity of clearing mechanism

This dimension is mainly affected by the type of clearing problem. The list of the most optimal bids to clear (and the cleared quantities of each) is formed based on the bids received (long-term and free capacity bids) from the FSPs and their impact factors. With the additional consideration of block bids (with linked acceptance levels), as well as bids with minimum cleared volumes or discrete cleared step sizes, as detailed in CoordiNet D4.4 [2], this increases the complexity of the clearing algorithm[14] (as compared to limiting the bids to simple hourly bids with zero acceptance ratio threshold). The reason is that the resulting problem to be solved is a mixed-integer linear program (a representative mathematical formulation, which includes minimum acceptable bid levels is presented in the case analysis in subsubsection 6.3.5.1). However, given the linear aspects of the formulation and given that the formulation does not include a full representation of the grid (i.e. aiming at only resolving the subscription level violation constraint), the complexity of the problem is manageable, especially when the number of submitted bids is limited.

6.3.5. Case Analysis

The goal of this case analysis is to investigate and assess two market aspects of the SE-1a BUC of the CoordiNet Swedish demonstration campaign. The first goal is to assess the possible drop in economic efficiency of the multi-level market model, implemented in Sweden, as compared to a common market model. The multi-level market model in the Swedish demonstration campaign differs from a common market model by giving priority to the local DSO to purchase flexibility from the local grid (in the first market stage) before making these resources available to the regional DSO (in the second market stage). This priority is not given in the common market model, in which all bids from all voltage levels are submitted to a single market cleared to jointly meet the flexibility needs of all the DSOs and TSOs. Our analysis shows, through developed examples, the potential impact of the multi-level scheme on the achieved market economic efficiency. The second aspect is to perform a sensitivity analysis of the market outcomes with respect to the defined impact factors to investigate the effect of minimal changes in the impact factors on the total cost to the system and the revenues of the participating FSPs. Indeed, the impact factors used in the Swedish demonstration campaign are computed in the planning phase and are static, i.e. they are not adapted to the state of operation of the grid, while in practice, impact factors depend on the grid state. Thus, one goal of the case analysis is to showcase how limited variations in the impact factors could lead to widely differing market outcomes. This, then, highlights the sensitivity of the market to these impact factors and gives insights on the need for dynamically and accurately updating these impact factors. These results, naturally, depend on the specific numerical setting used in the case study.

The case study will be based on two main parts. In the first, an illustrative example is developed to provide a tractable example on the decrease of market efficiency that could be induced by the multi-level market model, as compared to the common market, and to showcase the sensitivity of the market outcomes to the used impact factors. In the second part, an example stylized based on the SE-1a market settings is provided to investigate these two dimensions in a more elaborate and representative way.

To perform the case analysis, mathematical formulations of the multi-level and common market models are developed (accounting for minimum acceptable bid levels) first, following which the illustrative examples and SE-1a BUC-based case analysis are presented.

[14] Other temporal and intertemporal constraints such as minimum preparation periods, maximum endurance times (time during which the flexibility is activated) and minimum down time also increases the complexity of the clearing problem.

6.3.5.1. Mathematical Formulation: Multi-Level and Common Market Models with Minimum Acceptable Bid Levels

As defined in the Swedish demonstrator, the impact factors of a certain FSP connected at location i of DSO λ (where λ can represent either of the local DSOs, L_1 and L_2, or the regional DSO, R) with respect to the flow constraint over a connection point N (where N could be either A, B, or C), denoted by $x_{i,N}^{\lambda}$, specify the effect of the activation of 1 unit of flexibility on the flow over connection point N, and is such that $0 \leq x_{i,N}^{\lambda} \leq 1$. A schematic of the network configuration and impact factors are shown in Figure 14.

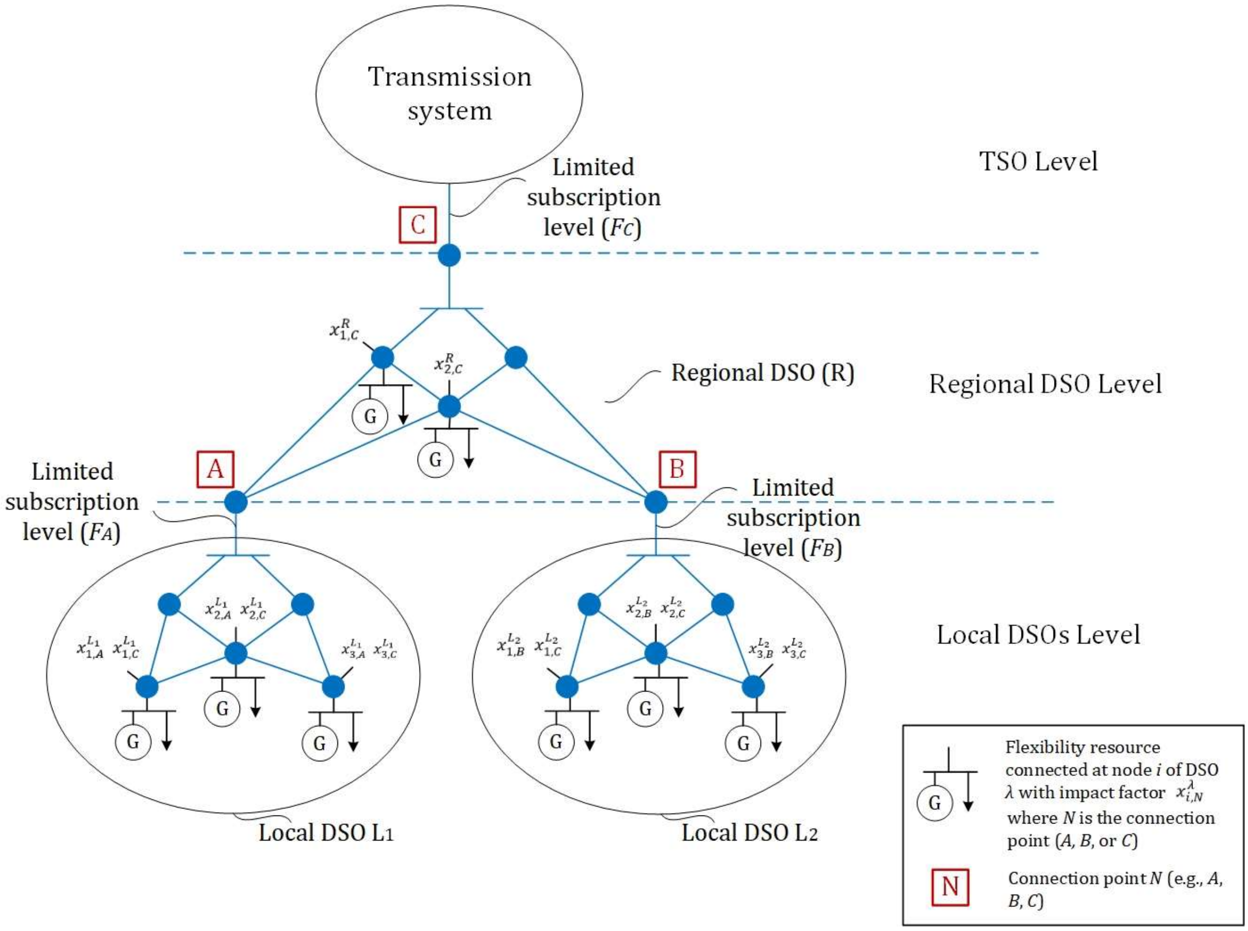


Figure 14: Network configuration showing two local DSOs (L_1 and L_2), one regional DSO (R), their connection points (A, B, and C) and the FSPs' impact factors.

In this regard, each FSP at a local DSO level is associated with two impact factors, one with respect to the local-regional DSO interconnection and one with respect to the regional DSO–TSO interconnection. For example, $x_{1,A}^{L_1}$ is the impact factor of the FSP at location 1 of local DSO L_1 with respect to the flow over connection point A, while $x_{1,C}^{L_1}$ is its impact factor with respect to connection point C. On the other hand, an FSP located at the regional level will only be associated with an impact factor with respect to the flow over the interconnection between the regional DSO and TSO. For example, $x_{1,C}^{R}$ is the impact factor of the FSP located at location 1 of the regional DSO grid with respect to the flow over connection point C.

Each FSP i connected at DSO level λ (i.e., L_1, L_2, or R) submits a price-quantity bid specifying the amount of flexibility that the FSP is willing to sell, denoted by $p_i^{\lambda,max}$, and the minimum accepted bid limit, denoted by $p_i^{\lambda,min}$ (indicating the minimum volume at which this bid is allowed to be cleared) at the unit price c_i^{λ}. If no lower limit is imposed as part of a particular bid, then $p_i^{\lambda,min} = 0$ for this bid.

The multi-level market model proposed in the Swedish demonstration campaign, can then be formulated based on 3 mathematical formulations, one for each local market and one for the regional DSO market, as shown in paragraphs 6.3.5.1.1 to 6.3.5.1.3. To include minimum accepted bid limits, binary decision variables $\mu_i^{\lambda} \in \{0,1\}$ and $\nu_i^{\lambda} \in \{0,1\}$ are defined, which multiply the submitted bids to capture the minimum acceptance level imposed by the bid.

6.3.5.1.1. Formulation of the local DSO market L_1

$$\min_{\boldsymbol{p}^{L_1},\boldsymbol{\mu}^{L_1}} \sum_{i\in M^{L_1}} c_i^{L_1} p_i^{L_1}, \tag{1}$$

Subject to

$$P_o^A - \sum_{i\in M^{L_1}} x_{i,A}^{L_1} p_i^{L_1} \le F^A, \tag{2}$$

$$\mu_i^{L_1} p_i^{L_1,min} \le p_i^{L_1} \le \mu_i^{L_1} p_i^{L_1,max} \; \forall i \in M^{L_1}, \tag{3}$$

$$\mu_i^{L_1} \in \{0,1\} \; \forall i \in M^{L_1}, \tag{4}$$

where P_o^A is the original flow over connection point A (i.e. without activation of any flexibility), and F^A is the subscription level at connection point A, i.e., between the local DSO L_1 and regional DSO, R.

6.3.5.1.2. Formulation of the local DSO market L_2

Similarly, the formulation at local DSO market L_2 is as follows:

$$\min_{\boldsymbol{p}^{L_2},\boldsymbol{\mu}^{L_2}} \sum_{i\in M^{L_2}} c_i^{L_2} p_i^{L_2}, \tag{5}$$

Subject to

$$P_o^B - \sum_{i\in M^{L_2}} x_{i,B}^{L_2} p_i^{L_2} \le F^B, \tag{6}$$

$$\mu_i^{L_2} p_i^{L_2,min} \le p_i^{L_2} \le \mu_i^{L_2} p_i^{L_2,max} \; \forall i \in M^{L_1}, \tag{7}$$

$$\mu_i^{L_2} \in \{0,1\} \; \forall i \in M^{L_2}, \tag{8}$$

where P_o^B is the original flow over connection point B (i.e. without activation of any flexibility) and F^B is the subscription level at connection point B, i.e., between the local DSO L_2 and regional DSO, R.

6.3.5.1.3. Formulation of the regional DSO market R

As the unused bids in the two local DSO markets are forwarded to the regional DSO market, which uses those bids and regional DSO level bids to clear the market, the formulation of the second level, i.e. regional DSO level, of the multi-level market taking into consideration minimum acceptance level of bids is as follows:

$$\min_{q^{L_1},q^{L_2},p^R,\mu^R,\nu^{L_1},\nu^{L_2}} \sum_{i\in M^{L_1}} c_i^{L_1} q_i^{L_1} + \sum_{i\in M^{L_2}} c_i^{L_2} q_i^{L_2} + \sum_{i\in M^R} c_i^R p_i^R, \tag{9}$$

Subject to

$$P_o^{C^*} - \sum_{i\in M^R} x_{i,C}^R p_i^R - \sum_{i\in M^{L_1}} x_{i,C}^{L_1} q_i^{L_1} - \sum_{i\in M^{L_2}} x_{i,C}^{L_2} q_i^{L_2} \le F^C, \tag{10}$$

$$P_o^{C^*} = P_o^C - \sum_{i\in M^{L_1}} x_{i,C}^{L_1} p_i^{L_1^*} - \sum_{i\in M^{L_2}} x_{i,C}^{L_2} p_i^{L_2^*}, \tag{11}$$

$$\mu_i^R p_i^{R,min} \le p_i^R \le \mu_i^R p_i^{R,max} \ \forall i \in M^R, \tag{12}$$

$$\left(1-\mu_i^{L_1^*}\right)\nu_i^{L_1} p_i^{L_1,min} \le q_i^{L_1} \le \nu_i^{L_1}\left(p_i^{L_1,max} - p_i^{L_1^*}\right) \ \forall i \in M^{L_1}, \tag{13}$$

$$\left(1-\mu_i^{L_2^*}\right)\nu_i^{L_2} p_i^{L_2,min} \le q_i^{L_2} \le \nu_i^{L_2}\left(p_i^{L_2,max} - p_i^{L_2^*}\right) \ \forall i \in M^{L_2}, \tag{14}$$

$$\nu_i^{L_1} \in \{0,1\} \ \forall i \in M^{L_1}, \tag{15}$$

$$\nu_i^{L_2} \in \{0,1\} \ \forall i \in M^{L_2}, \tag{16}$$

$$\mu_i^R \in \{0,1\} \forall i \in M^R. \tag{17}$$

Here, $p_i^{L_1^*}$ and $p_i^{L_2^*}$ are cleared portions of the submitted bids, respectively, $p_i^{L_1,max}$ and $p_i^{L_2,max}$, in the local DSO markets stage, and $\mu_i^{L_1^*}$ and $\mu_i^{L_2^*}$ are the values of the binary decision variables at the optimal solution of the local markets. This formulation includes new binary variables, $\nu_i^{L_1}$ and $\nu_i^{L_2}$, used for limiting the accepted bids from the local DSOs. In addition, $q_i^{L_1}$ and $q_i^{L_2}$ are introduced as new decision variables, denoting the accepted bids in the regional-level market from flexibilities located in L_1 and L_2, respectively. This notation is added to differentiate between the decision variables in the first and second levels of the market. Moreover, P_o^C is the original flow over connection point C before the clearing of the local markets and $P_o^{C^*}$ is the flow over connection point C after the clearing of the local markets. Two options can be considered here to account for the effect of the activation of the local bids in the local market on the flow over connection point C (i.e., the flow between the regional and transmission grids over connection point C):

1. In the first option, $P_o^{C^*}$ is set before the multi-level market is run, in which case equation (11) would not be considered and $P_o^{C^*} = P_o^C$. In other words, in this case, the amount of flexibility that the regional DSO needs to purchase is set before the run of the market and does not take into consideration the results of the first stage of the multi-level market (i.e. the local markets). Hence, the needs of the regional DSO are not adjusted after the clearing of the local markets.
2. In the second option, $P_o^{C^*}$ is adapted to account for the flexibility activated in the first stage, i.e., $P_o^{C^*} = P_o^C - \sum_{i\in M^{L_1}} x_{i,C}^{L_1} p_i^{L_1^*} - \sum_{i\in M^{L_2}} x_{i,C}^{L_2} p_i^{L_2^*}$), as captured in equation (11). This is the setting that will be considered in the numerical results presented throughout this case analysis.

F^C is the subscription level at connection point C, i.e., between the regional DSO R and the TSO.

6.3.5.1.4. Mathematical Formulation of a Common Market

To compare between the economic efficiency of the multi-level market used in the SE-1a BUC of the Swedish demonstration campaign and the common market model, the mathematical formulation of the common market model is provided next.

The main difference between the multi-level market model described above and the common market model is that the multi-level market model gives priority to the local DSOs to use local flexibility first, before making it available to the regional DSO. The formulation of the common market model, which, on the contrary, combines the offers of all flexibility resources (from L_1, L_2, and R) in a single market to solve the constraints of all DSOs, is provided next.

$$\min_{\boldsymbol{p}^{L_1},\boldsymbol{p}^{L_2},\boldsymbol{p}^{R},\boldsymbol{\mu}^{R},\boldsymbol{\mu}^{L_1},\boldsymbol{\mu}^{L_2}} \sum_{i\in M^{L_1}} c_i^{L_1} p_i^{L_1} + \sum_{i\in M^{L_2}} c_i^{L_2} p_i^{L_2} + \sum_{i\in M^{R}} c_i^{R} p_i^{R}, \tag{18}$$

Subject to

$$P_o^A - \sum_{i\in M^{L_1}} x_{i,A}^{L_1} p_i^{L_1} \leq F^A, \tag{19}$$

$$P_o^B - \sum_{i\in M^{L_2}} x_{i,B}^{L_2} p_i^{L_2} \leq F^B, \tag{20}$$

$$P_o^C - \sum_{i\in M^{R}} x_{i,C}^{R} p_i^{R} - \sum_{i\in M^{L_1}} x_{i,C}^{L_1} p_i^{L_1} - \sum_{i\in M^{L_2}} x_{i,C}^{L_2} p_i^{L_2} \leq F^C, \tag{21}$$

$$\mu_i^{L_1} p_i^{L_1,min} \leq p_i^{L_1} \leq \mu_i^{L_1} p_i^{L_1,max} \ \forall i \in M^{L_1}, \tag{22}$$

$$\mu_i^{L_2} p_i^{L_2,min} \leq p_i^{L_2} \leq \mu_i^{L_2} p_i^{L_2,max} \ \forall i \in M^{L_1}, \tag{23}$$

$$\mu_i^{R} p_i^{R,min} \leq p_i^{R} \leq \mu_i^{R} p_i^{R,max} \ \forall i \in M^{R}, \tag{24}$$

$$\mu_i^{L_1} \in \{0,1\} \ \forall i \in M^{L_1}, \tag{25}$$

$$\mu_i^{L_2} \in \{0,1\} \ \forall i \in M^{L_2}, \tag{26}$$

$$\mu_i^{R} \in \{0,1\} \ \forall i \in M^{R}, \tag{27}$$

6.3.5.2. Illustrative Examples

6.3.5.2.1. Illustrative Example 1: Multi-Level vs. Common Market Models

The example presented here highlights the possible disadvantages introduced by giving priority to clear the local markets first as part of the multi-level market model in the Swedish demonstration campaign, as compared to the common market model.

In this illustrative example, one local DSO L_1 and one regional DSO R are considered, each containing two flexibility resources. In addition, it is assumed that the violation of flow at connection point A is 3 MW and at connection point C is 36 MW. Hence, the respective markets should purchase capacity to lower the flow over connection point A by at least 3 MW and at connection point C by at least 36 MW.

The following two tables summarize the considered impact factors of each of the four flexibility resources, with respect to the flow over connection points A and C, as well their submitted bids (including a minimum and maximum bid quantity and associated price).

Table 10: Bid Parameters in L_1

Flexibility resource index $[i]$ in L_1	Impact factor w.r.t F_A, $[x_{i,A}^{L_1}]$	Impact factor w.r.t F_C, $[x_{i,C}^{L_1}]$	$p_i^{L_1,min}$ (MW)	$p_i^{L_1,max}$ (MW)	Price, $[c_i^{L_1}]$ (€/MW)
1	1.00	0.70	0.00	15.00	10.00
2	1.00	0.70	5.00	15.00	8.00

Table 11: Bid Parameters in R

Flexibility resource index, $[i]$ in R	Impact factor w.r.t F_A	Impact factor w.r.t F_C, $[x_{i,C}^R]$	$p_i^{R,min}$ (MW)	$p_i^{R,max}$ (MW)	Price, $[c_i^R]$ (€/MW)
1	0	0.80	0.00	20.00	6.00
2	0	0.80	0.00	20.00	7.00

As can be seen from the bid parameters, the bid of resource 2 in L_1 is the only bid that is submitted with a minimum power limit.

Applying the formulations of the multi-level market model and the common market model, presented in subsubsection 6.3.5.1, the following optimal market clearing results are obtained.

Table 12: Cleared quantities for L_1 flexibility resources in the multi-level and common market models

Flexibility resource index $[i]$ in L_1	Total cleared power in the multi-level market (MW)	Total cleared power in the common market (MW)
1	3.00	0.00
2	5.00	5.71

Table 13: Cleared quantities for R flexibility resources in the multi-level and common market models

Flexibility resource index $[i]$ in R	Total cleared power in the multi-level market (MW)	Total cleared power in the common market (MW)
1	20.00	20.00
2	18.00	20.00

As can be seen from the market clearing results, resource 1 in L_1 is only cleared in the multi-level market, due to the minimum bid size restriction of resource 2 of L_1. In fact, even though resource 2 of L_1 is cheaper, it is not cleared in the first level of the market. In addition, in the multi-level market model, resource 2 of R is not fully cleared in the second market level, in order to take advantage of resource 2 in L_1 and prevent the use of resource 1 in L_1 in the second market level. Indeed, based on the multi-level market outcome, in the local market (i.e. the first stage of the multi-level market), resource 1 of L_1 delivers 3 MW and resource 2 of L_1 0 MW; while in the second level of the market (i.e., the regional level), resource 1 of L_1 delivers 0 MW and resource 2 of L_1 5 MW.

Table 14 presents a summary of costs of the two markets and purchased flexibility. Here we note that the total costs correspond to the value of the objective functions of the two market clearing models, i.e. the addition of (1) and (9) for the multi-level market and (18) for the common market, computed at the optimal solutions, which, hence, intrinsically considers (only in the illustrative examples) a pay-as-bid renumeration scheme. Here, we note that both uniform pay-as-cleared and pay-as-bid pricing mechanisms are investigated in the more elaborate case analysis in subsubsection 6.3.5.3.

Table 14: Markets' Costs and Flow Constraints

Market Model	Multi-Level Market	Common Market
Total cost (€)	316	305.68
Total decrease in F_A (MW)	8	5.71

Total decrease in F_C (MW)	36	36

As can be seen in Table 14, the multi-level market leads to a higher cost of purchasing flexibility. In addition, the multi-level market yields a higher decrease in the flow over connection point A (8 MW as compared to 5.71 MW in the common market model), which is more than is actually needed (3 MW). This, hence, shows that, in this example, the multi-level market model led to a higher cost of purchasing flexibility and a higher amount of flexibility purchased than needed. In fact, in this example, stemming from the imposed minimum bid sizes, the multi-level market model has prevented the allocation of resources in the most economic manner leading to a drop in efficiency, measured based on the total incurred system costs, as compared to the common market model. In this example, the multi-level market model leads to a 3.4% increase in costs.

6.3.5.2.2. Illustrative Example 2: Sensitivity of Market Outcomes to Impact Factors

Another illustrative example is used here to showcase the effect of minimal perturbations in the impact factors on the markets' outcomes. This highlights the importance of a proper, accurate, and transparent calculation of the impact factors, as small perturbations could have a significant effect on the total system costs, as well as on the revenues of the participating FSPs.

Consider the case in which the impact factors of resource 2 in L_1 and resource 2 in R are slightly modified (as compared to Table 10 and Table 11), while all other bid parameters are kept the same, as shown in Table 15 and Table 16, where the modified impact factors are marked in **red**.

Table 15: Bid Parameters in L_1

Flexibility resource index $[i]$ in L_1	Impact factor w.r.t F_A, $[x_{i,A}^{L_1}]$	Impact factor w.r.t F_C, $[x_{i,C}^{L_1}]$	$p_i^{L_1,min}$(MW)	$p_i^{L_1,max}$(MW)	Price, $[c_i^{L_1}]$ (€/MW)
1	1.00	0.70	0.00	15.00	10.00
2	1.00	**0.80**	5.00	15.00	8.00

Table 16: Bid Parameters in R

Flexibility resource index $[i]$ in R	Impact factor w.r.t F_A	Impact factor w.r.t F_C, $[x_{i,C}^{R}]$	$p_i^{R,min}$(MW)	$p_i^{R,max}$(MW)	Price, $[c_i^{R}]$ (€/MW)
1	0	0.80	0.00	20.00	6.00
2	0	**0.70**	0.00	20.00	7.00

The resulting market outcomes are as shown in Table 17 and Table 18, where the differences in cleared quantities as compared to Table 12 and Table 13 are highlighted in red.

Table 17: Cleared quantities for L_1 flexibility resources in the multi-level and common market models

Flexibility resource index $[i]$ in L_1	Total cleared power in the multi-level market (MW)	Total cleared power in the common market (MW)
1	3.00	0.00
2	5.00	**7.5**

Table 18: Cleared quantities for R flexibility resources in the multi-level and common market models

Flexibility resource index $[i]$ in R	Total cleared power in the multi-level market	Total cleared power in the common market
1	20.00	20.00
2	**19.86**	20.00

The resulting total costs (compared to the total costs resulting from the original impact factors shown in Table 14) are shown in Table 19.

Table 19: Markets' Costs

Total Cost (€)	Original Impact Factors	Modified Impact Factors
Multi-level market	316	**329**
Common market model	305.68	**320**

It must be noted that the clearing of the market is not necessarily unique (as multiple solutions may exist), but each of the optimal solutions would result in the same optimal total cost (shown in Table 19). Hence, the comparison of the effects of the impact factors on the basis of the incurred total costs holds in the presence of multiple possible optimal solutions.

As can be seen in Table 19, the increase of the impact factor of FSP 2 in L_1 by 0.1 and the decrease in the impact factor of FSP 2 in R by 0.1, lead to an increase in system costs by 4.12% and 4.68% for the multi-level market and common market models, respectively.

Therefore, this illustrative example met its goal to highlight the effect of minimal modifications in the impact factors on the market outcomes in a tractable manner, by limiting the number of FSPs to four and considering only one local DSO and the regional DSO. A more elaborate case analysis is shown in the next subsubsection.

In fact, illustrative examples 1 and 2 (provided in, respectively, paragraphs 6.3.5.2.1 and 6.3.5.2.2) are stylized illustrative examples showcasing the decrease in economic efficiency that the common market model can induce, as well as the sensitivity of the solution to the defined impact factors. Next, a more elaborated case study is considered, which reflects, to a varying extent, the settings of the SE-1a BUC of the CoordiNet Swedish demonstration campaign to highlight these two elements.

6.3.5.3. Case Analysis focusing on the SE-1a BUC Settings

This case study is inspired by the settings run in Uppland during the winter 2019/2020 demo run. As shown in Figure 7 of CoordiNet D4.5 [22], this market includes one regional market and two local markets (Upplands Energi and Uppsala North). As shown in Table 2 of CoordiNet D4.5 [22], this market contains 8 different FSPs, along with their type of technologies, the system to which they are connected and their maximum capacity. The impact factors of each of these FSPs with respect to each of the connection points is provided in Table 16 of D4.5 [22].

In this regard, the goal of this case analysis is not to completely replicate the settings of the demonstration campaign, but rather to create an example that is based on the settings of the Swedish demonstration campaign to compare i) the economic efficiency of the multi-level market model as compared to the common market model, and ii) highlight the sensitivity of the market outcomes to the defined impact factors. As such, Table 20 enumerates the eight FSPs along with their associated defined parameters that are used in this case study. Here, note that for completeness of our numerical analysis, we have considered minimum bid sizes to be equal to 10% of the maximum capacity for all FSPs except for FSPs 3 and 6, which we consider to be aggregation of three flexible units. In those cases, we took the minimum bid size to be the capacity of one of the units (i.e. the maximum capacity divided by three). In addition, we have added stylized bid prices for the bids to complete our numerical analysis and considered that the flexibility need of each local DSO is 1 MW and the flexibility need of the regional DSO to be 20 MW. In other words, each local DSO aims to decrease the flow over their connection point with the regional DSO by 1 MW, while the regional DSO aims at purchasing flexibility to decrease the flow over its connection point with the TSO by 20 MW.

Table 20: FSPs Bid Parameters, Impact Factors, and System Level Connection

FSP ID	Min. Bid Quantity (MW)	Max. Bid Quantity (MW)	Bid Price (€/MW)	System level Connection	Impact Factor TSO - Regional Connection	Impact factor L_1 - Regional Connection	Impact factor L_2 - Regional Connection
1	0.15	1.5	16	Local DSO 1 (L_1)	0.85	0.9	0
2	0.10	1	25	Local DSO 2 (L_2)	0.85	0	1
3	0.15	0.45	20	Local DSO 2 (L_2)	0.85	0	1
4	0.01	0.025	18	Local DSO 2 (L_2)	0.79	0	0.83
5	6.00	60	15	Regional DSO (R)	0.85	0	0
6	8.00	24	15	Local DSO 2 (L_2)	0.85	0	1
7	1.00	10	8	Regional DSO (R)	0.85	0	0
8	1.60	16	50	Regional DSO (R)	0.85	0	0

For this case analysis, hence, two different coordination schemes (the common market model and the Swedish multi-level market model) are considered, where a uniform pay-as-cleared and a pay-as-bid pricing mechanisms are investigated for each of them.

6.3.5.3.1. Comparison between the common and multi-level market models

Figure 15 and Figure 16 provide an illustration of, respectively, the cleared volumes for each FSP in the multi-level and common market models and the corresponding acceptance ratios, as compared to their maximum bid quantities.

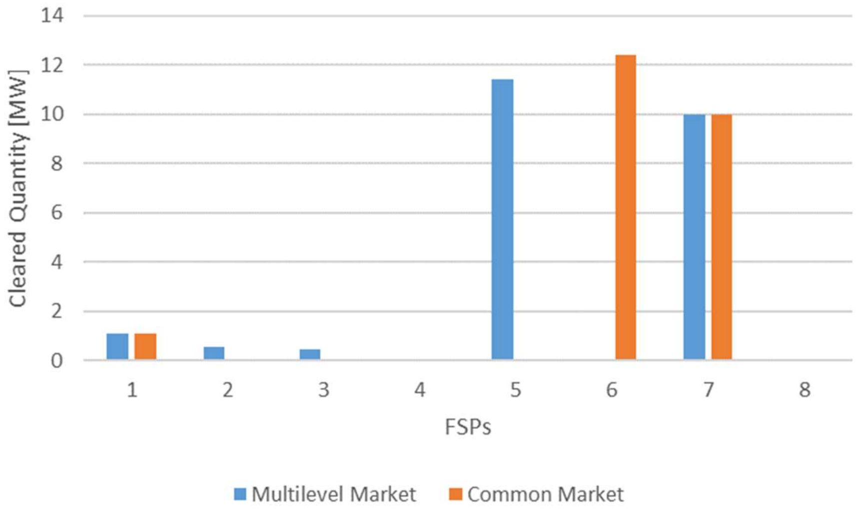


Figure 15: Accepted Quantities of Each FSP under the Multi-Level vs. Common Market Models

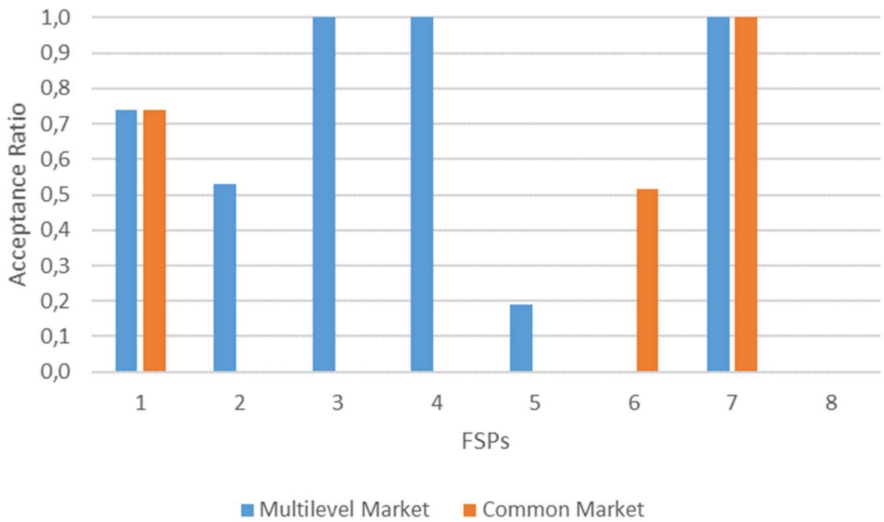


Figure 16: Accepted Ratio (as compared to the maximum bid quantity) of Each FSP under the Multi-Level vs. Common Market Models

As can be seen from Figure 15 and Figure 16, the coordination scheme (i.e. multi-level vs. common) has a direct effect on the FSPs' level of participation in the market (i.e. their cleared volumes). For example, FSPs 2, 3, 4, and 5 are able to participate in the multi-level market through cleared bids (with FSPs 3 and 4 being fully cleared, as shown in Figure 16) but not in the common market, while FSP 6 was able to have its bid (partially) cleared in the common market model but not in the multi-level market model. In fact, in the common market model, FSP 6 takes up all the quantities of FSPs 2, 3, 4, and 5, which would have been cleared in the multi-level market. The reason for that is that FSP 6, located in L_2, has a relatively large minimum bid size, which prevents it from participating in the local and regional markets under the multi-level market model. However, in the common market, as FSP 6 can contribute to both the local and regional markets, its optimal cumulative contribution of the two markets exceeds its minimum bid size allowing it to be cleared in the common market instead of FSPs 2-5. On the other hand, FSPs 1, 7, and 8 are not affected by the coordination scheme as their level of cleared bids is similar in the multi-level and common markets. In fact, FSP 1 is the only FSP located in L_1, and hence is the only FSP which can contribute to the flexibility need of local DSO 1 (i.e. the only FSP with an impact factor with respect to the L_1 – Regional connection that is non-zero). In that case, FSP1 would be cleared at the same level in both coordination schemes and, in fact, it holds market power (as a monopolist in that case). This reflects the case of the "Aggregator" in Table 2 of CoordiNet D4.5 [22], which is the only FSP in the "Uppland Energi" local market. FSP 7 submitted the cheapest bid and has the highest impact factor for the Regional – TSO interconnection and, hence, maintains the same participation level in the two markets (i.e. FSP 7 would be fully cleared in both coordination schemes). As for FSP 8, its bid is significantly more expensive than all other FSPs and, hence, is not cleared in any of the two coordination schemes.

Here, note that due to the relatively small capacity of FSP 4 as compared to the other FSPs, even though it is fully cleared in the multi-level market (as shown in Figure 16), its cleared quantity is barely visible in Figure 15, simply due to its small scale.

Table 21 shows the resulting revenues for each FSP under the common and multi-level market models for a pay-as-cleared and pay-as-bid pricing mechanisms, as well as the total cost incurred by the DSOs (shown in the last row in grey). It must be noted that the problem solved by the DSOs for clearing the market is assumed to be the same under the two pricing schemes (leading to the same clearing results, shown in Figure 15, for both remuneration schemes), while the revenues of the FSPs and the costs are calculated ex-post based on the market outcome. As the same bids by the FSPs (shown in Table 20) are used in clearing the market (irrespective of the remuneration scheme), the case analysis considers intrinsically that the bidding behavior of the FSPs does not change based on the pricing mechanism. Even though this would not capture the strategic behavior of each FSP, which would be adapted to the remuneration scheme, this assumes a constant truthful bidding behavior to allow for the comparison between the coordination schemes just on the basis of the coordination scheme itself, while keeping other market parameters constant.

Table 21: FSPs' Revenues and DSOs' Total Costs in Multi-Level and Common Market Models under Pay-as-Cleared and Pay-as-Bid Pricing Schemes

	Multilevel Market						Common Market	
	Pay-As-Bid (€)			Pay-As-Cleared (€)			Pay-As-Bid (€)	Pay-As-Cleared (€)
FSP ID	Local Market	Regional Market	Sum	Local Market	Regional Market	Sum		
1	17.78		17.78	19.75		19.75	17.78	19.61
2	13.23		13.23	13.23		13.23		
3	9.00		9.00	11.25		11.25		
4	0.45		0.45	0.62		0.62		
5		171.24	171.24		201.46	201.46		
6			-			-	186.27	219.15
7		80.00	80.00		176.47	176.47	80.00	176.47
8			-			-		
Total	40.46	251.24	291.70	44.85	377.93	422.78	284.05	415.23

As can be seen from the total costs in Table 21 (presented in green for pay-as-cleared and blue for pay-as-bid), the multi-level market model leads to an increase in total costs for the DSOs as compared to the common market model under both pricing schemes. This, hence, highlights the possible drop in economic efficiency caused by the priority given in the multi-level market model to the first clearing level (i.e. the local DSO in this case) to use the local flexibility bids before making them available to the regional level. The revenues of the FSPs in Table 21 further highlight the results of Figure 15 and Figure 16 by showing the drop in revenues for FSPs 2, 3, 4, and 5 and the significant increase in revenues of FSP 6 in the common market model as compared to the multi-level model.

6.3.5.3.2. Impact Factors Sensitivity Analysis

This paragraph of the case analysis investigates the sensitivity of the market outcomes to the impact factors. To this end, the sensitivity analysis considered a 10% increase and a 10% decrease in the nominal impact factors of each FSP shown in Table 20. This leads to three possible values for each of the impact factors of the FSPs, namely $0.9\mathrm{x}_{\mathrm{i,N}}^{\lambda}$, $\mathrm{x}_{\mathrm{i,N}}^{\lambda}$, and $1.1\mathrm{x}_{\mathrm{i,N}}^{\lambda}$, where $\mathrm{x}_{\mathrm{i,N}}^{\lambda}$ is the nominal impact factor of FSP i connected at DSO level λ with respect to the flow over connection point N. The combination of all possible values of these impact factors variations were considered (each possible combination of impact factor values for the eight FSPs was labelled as an impact factor "sample") and each of the resulting markets was solved for each possible sample. Here, the focus was solely on the multi-level market model to capture the market structure implemented in the SE-1a BUC and analyze the sensitivity of this market to the defined impact factors.

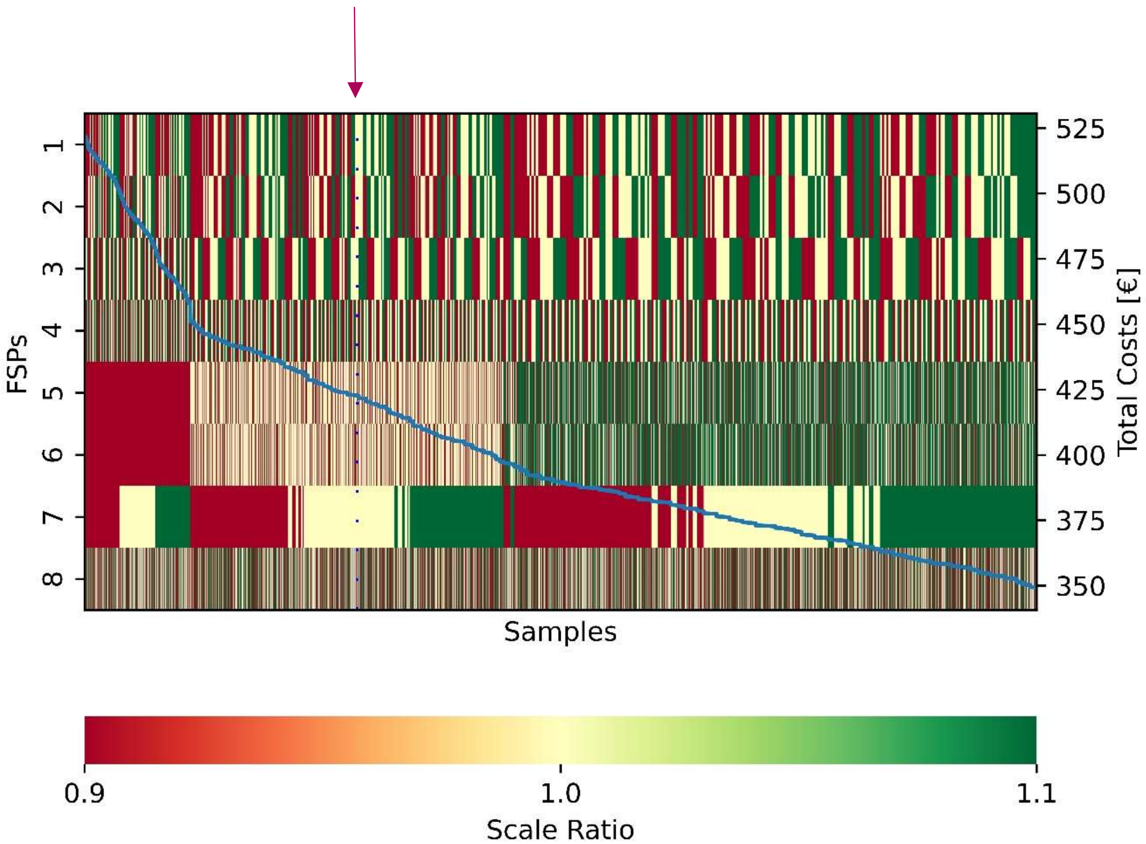


Figure 17: Variation of total system cost for different impact factor samples under a uniform pay-as-cleared pricing scheme

Figure 17 shows the resulting total system cost for each impact factor sample, where the samples are sorted in descending order based on the resulting total system cost. For each of the eight FPSs (i.e. the left-hand side vertical axis), the red, light yellow, and green colors indicate, respectively, an impact factor value reduced by 10% as compared to the nominal value, the nominal value, and an impact factor value increased by 10% as compared to the nominal value. The right-hand vertical axis in Figure 17 indicates the total system cost, and the blue curve shows the variation of the total system cost with respect to the different impact factor samples. For reference, the nominal sample (i.e. the sample in which each of the FSPs has an impact factor equal to its nominal value) is specified using the dashed vertical line (and indicated by an arrow).

The first major observation that could be drawn from Figure 17 is the high variability of the total system cost with respect to relatively small variations in the impact factors. In fact, the difference between the maximum (i.e. leftmost) and minimum (i.e. rightmost) resulting system costs is 49.4%. This, hence, highlights the importance of having accurate impact factors for the operator. Here, it is important to note that given that the outcome of the market does not only depend on the bid submitted by a certain FSP (or the impact factor of that FSP) but rather on the combination of submitted bids; one may not take one FSP in isolation to determine a trend mapping the effect of its impact factor on the total system cost. Indeed, that is reason for which Figure 17 does not show that the left-hand side of the figure (i.e. the side reflecting high total costs as indicated by the blue curve) to be all in red (i.e. combinations of low impact factors) and the right-hand side (i.e. the side reflecting low total costs) to be all in green (i.e. combinations of high impact factors). In fact, a perturbation in the impact factor of one FSP could at some instances (depending on the combination of impact factors of the other FSPs and on its bid compared to the other FSPs) significantly change the market outcome (bringing this FSP in or out of the market) and total system costs, while in other situations this perturbation may not have any (or minimal) effect on the market. For example, the seemingly interchangeable occurrences of the impact factors of FSPs 4 and 8 in Figure 17 indicate their minimal effect on influencing the total system cost. In fact, FSP 4's offered capacity is significantly low, limiting its effect on the system cost, while FSP 8's bids are never accepted in any of the samples due to its high bid price, rendering its impact factor irrelevant to the total cost.

The modification in the impact factors does not only have a direct effect on the system cost but also on the revenues of the different FSPs, as shown in Figure 18. In this figure, the vertical axis shows each FSP's relative revenue, as compared to its maximum possible revenue for all impact factor samples. The revenues of the FSPs shown in Figure 18 are sorted in descending order independently for each FSP for the different samples. This sorting is, hence, different for each of the FSPs. FSP 8 is not represented in the figure, as its revenue is equal to 0 for all impact factor samples because its bid is never cleared in the market for any impact factor combination.

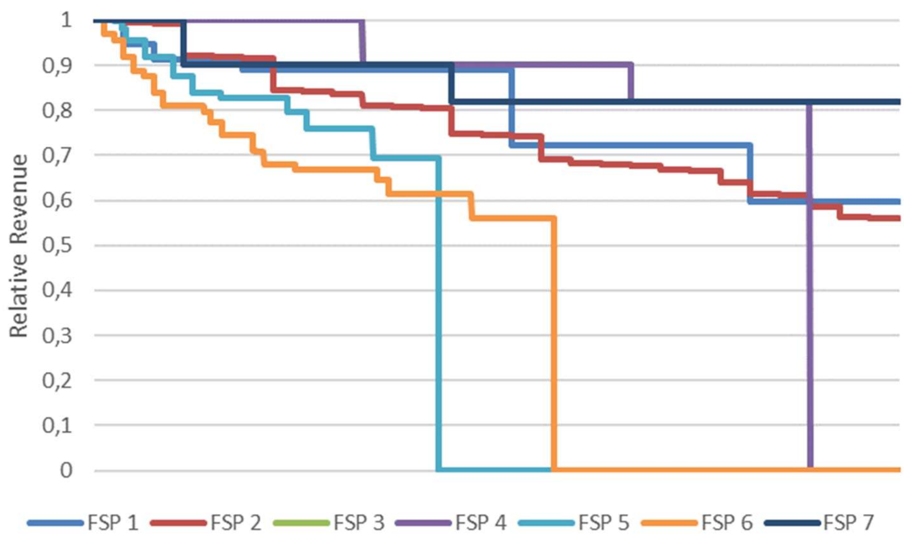


Figure 18: Variation in the FSPs relative total revenue as compared to the maximum possible revenue for different impact factors samples under a uniform pay-as-cleared pricing scheme

Figure 18 highlights the significant effect that the impact factors have on the FSPs' revenues and, hence, reinforces the need for a transparent and accurate calculation of these impact factors. In fact, the impact factors are not controlled by the FSP, but are rather a result of its location within the grid and the interconnection of the grid. Hence, errors in the calculation of the impact factors can favor or disfavor a certain FSP, directly affecting its revenues and, hence, its willingness to participate in the market. Figure

18 also indicates the sensitivity of each FSP to the change in impact factors. In fact, a shallow curve in Figure 18 (such as the case, e.g., for FSP 7) indicates that the FSP's revenues are not highly affected by the impact factors, while a steep curve (as is the case, e.g., for FSP 5) indicates a high sensitivity of the FSP to the impact factors. Therefore, this shows that some FSPs are more impacted than others by the variation of – and, hence, the errors in – the impact factors.

6.3.5.4. Conclusions

This case analysis has highlighted two aspects that are of high relevance to the market model implemented in the SE-1a BUC of the Swedish CoordiNet demonstration campaign. In the first, the case analysis has shown the possibility of decreasing the economic efficiency of the market by giving priority to the local DSO, in a multi-level market model, to first access and clear local flexibility resources before making these resources available to the regional DSO. Indeed, in the studied example, the multi-level market model led to higher system costs than the common market model (which does not give such a priority, but rather pools all bids from all voltage levels into one market to meet all of the DSOs' flexibility needs). In the second aspect, this case analysis has highlighted the importance of an accurate and transparent calculation of the impact factors for the clearing of the market. In fact, the sensitivity analysis has shown a high variability in the total costs and the FSPs revenues to small (10%) variations in the impact factors. Hence, this highlights the need for a continuous and dynamic re-calculation of the impact factors to accurately compute their exact values to prevent inducing a bias to the market outcomes, increasing the total system costs, and affecting the FSPs' potential revenues.

6.3.6. Possible improvements

In addition to the improvements discussed as part of the previous analyses in subsections 6.3.4 and 6.3.5 along the different assessment criteria, a summarized list of suggestions highlighting the possible directions of improvement are provided in the following.

Improvements to market efficiency can be achieved by considering a common market model which does not prioritize access to flexibility resources among the different DSOs. This would enable a more efficient use of the available flexibility resources, leading to a higher market efficiency. An additional aspect which could improve market efficiency is allowing FSPs to re-adjust their bids between the clearing of the local market and the regional market. The ability to adjust the bids would allow an FSP to re-adjust its offering strategy (i.e. quantities and prices) in the next market based on the outcome (i.e. clearing) of the previous market, as well as changes in the FSPs' portfolio. This enables FSPs to enhance their revenues, creating more incentives for these FSPs to remain in the market and for new FSPs to join. This, as a result, can lead to an improved liquidity in the market. However, this would introduce variability to the available flexibility at the disposal of the regional DSO (second market stage), introducing uncertain elements for which the regional DSO must account. In addition, this can increase the risk of gaming. Hence, proper monitoring of the market would be needed to remove such gaming potential when allowing for bid adjustments between market sessions.

Regarding the timing of the market, the time granularity for the congestion management market (60 minutes) is in line with the current practice in Sweden, as it coincides with the imbalance settlement period, as well as the market time unit in the Swedish mFRR, day-ahead, and intraday wholesale markets. However, for synergy and consistency with current and future European markets (as well as with future Swedish electricity markets), adapting the market timing by using a 15-minute market time unit and a 15-minute imbalance settlement period would be necessary. This would enable to interconnectivity of the market with other cross-border markets allowing an interconnected trading of flexibility.

Regarding transparency and scalability, allowing manual adjustments by the DSO to the clearing progress would face difficulties when the scale of the system and number of bids significantly increases. Moreover, manual selection of bids instead of an automatic clearing with defined rules may impact transparency. A potential improvement in this regard could be to allow for automatic clearing which could be re-run by the respective DSO to account for the possible late arrival of needed information.

Regarding grid constraints, the impact factor is the only location-dependent information with which an FSP or a flexibility bid is associated. This could raise challenges when not only subscription levels are considered for congestion management (i.e. the capacity between the different grids), but also when considering nodal voltages and line flow constraints (in addition to other possible operational constraints ensuring a secure operation and a high quality of supply). In that case, these impact factors would not be sufficient, as more specific locational information (e.g. at the node level) would be needed. Therefore, a potential improvement would be to require nodal information for the bids and to include additional grid constraints in the market clearing process. In addition, the current mechanism relies on static impact factors, which were defined and computed prior to the run of the pilot (i.e. during the planning phase). A potential improvement consists of using dynamic impact factors, which take into consideration the dynamic changes in the state of operation of the system for computing the impact factors at a given time period.

6.4. Market design analysis of GR-2a and GR-2b

6.4.1. Introduction to the analysis

This analysis refers to the Greek demonstrators realized within the CoordiNet Project, focusing specifically on GR-2a and GR-2b. The reason is that GR-1x demonstrators are looking for ways to solve voltage problems, while GR-2x demonstration campaigns aim at analysing different coordination schemes to solve congestion problems within the transmission and distribution network. They are therefore the relevant ones to investigate in the context of this analysis.

The section is structured as follows. First, more details will be given regarding the context of these demonstrators, as well as the differences between the coordination schemes in a theoretical perspective. Second, a performance evaluation will be undertaken on a toy example to assess the performance of the schemes before comparing them. This latter part will rely on different simulated markets set up in AMPL, an optimization programming language.

6.4.2. Description of the schemes investigated

6.4.2.1. Theoretical overview

GR-2a and GR-2b focusing on congestion management are presented in detail in Table 50. In short, GR-2a envisages a multi-level market coordination scheme while GR-2b relies on a fragmented market structure. The difference is highlighted by Figure 19 and Figure 20. Furthermore, a succinct presentation of these models is proposed below as a refresher.

Multi-Level Market Model

The multi-level market model promises an interesting coordination scheme, with the aim to forward as many non-used flexibilities offers as possible from the DSO (local) market to the TSO (central) market. It achieves this by taking profit from an asynchronization of both markets, as highlighted on Figure 19.

Figure 19: Multi-Level Market Model Organization

Even though this coordination scheme requires a medium amount of interactions between system operators and also leads to a low amount of liquidity in the markets while compared with other schemes [35], it has the big advantage to explicitly take profit of non-used offers from distribution level to the transmission one. Nevertheless, this comes with the key challenge of making the bids available to the TSO, while ensuring that the TSO activations will not create any issue on the DSO grid, despite not necessarily being able to see all the DSO constraints. This issue will be later analysed, by describing how it is considered in the demonstrator before analysing it quantitatively on a toy example.

Fragmented Market Model

Even though it is classified as a coordination scheme, the fragmented market model is certainly the one proposing the least coordination possible. Indeed, as revealed in Figure 20, both the TSO and the DSO benefit from their own exclusive market.

Figure 20: Fragmented Market Model Organization

The fact that, once offered through a market, inactivated bids are not allowed to be transferred to the other market has the key advantage to require a medium amount of interactions between system operators [35]. However, it is done at the price of allowing few economies of scale. This last remark will be supported more formally later on through the quantitative analysis.

Common Market Model

In order to be able to benchmark these coordination schemes, a more standard common market model will also be used all along this analysis: the common market model.

The common market model is simply a market where both the TSO and the DSO have access as buyers of flexibility offers. On the other side of the market, FSPs sell their flexibility according to their valuation of it thanks to offer bids. Again, a simple representation revealing the difference with the two previous schemes is given in Figure 21.

Figure 21: Common Market Model Organization

This figure highlights the fact that both the TSO and the DSO are involved in the same market at the same time with the same access to offer bids. When compared with the other schemes, this one requires a low amount of interactions between system operators and leads to a higher level of liquidity of the market [35].

6.4.2.2. Link with the reality

According to the Work Package 5 of the CoordiNet Project, the bids split and transfer management can be explained as follow. When the fragmented market model is implemented, the TSO does not have access to the FSPs in the distribution system. In case of the multi-level market model, the remaining bids from the local market are transferred to the TSO market. However, the DSO cannot transfer all the remaining bids to the TSO market, but only those whose activation will not cause any grid issues (voltage violation, congestion) in the distribution system.

The process of transferring the bids implements two steps:

- After the local market clearance, the DSO filters out the remaining bids that meet the criteria for participating in the TSO market (according to product attributes and the characteristics of the FSPs.). It is noted that the FSPs have already registered in the local and TSO markets that they want and can participate. Therefore, this “prequalification” is carried out based on this information.

- Then, the DSO must decide the bids whose activation will not lead to a voltage violation or congestion in the distribution system and, then, transfer them to the TSO market. Based on an optimization algorithm, similar to the one used for the local market clearance, the maximum capacity/energy that can be activated is calculated. The constraints of the problem take into account the voltage limits, the capacity of lines and transformers, etc. The only difference compared to the optimization problem of the local market clearance is the objective function. Regarding the transfer of the remaining bids to the TSO market, the objective function could be the maximization of the transferred energy/capacity. In addition, the cost of the bids could be added to the objective function using different weights for the transferred capacity/energy and bids’ price.

So, in this second step, an optimization problem is solved to determine the maximum amount of energy that can be exported out of the distribution system. The grid constraints are taken into account, either by explicitly modelling them or using sensitivity coefficients without considering network topology. Sensitivity coefficients can be also used to determine the FSPs that can assist in solving the grid violations and then solve the optimization problem, where the grid constraints are explicitly modelled, considering only these FSPs. In that way, we can simplify the optimization problem can be simplified.

At the time of writing this deliverable, the market algorithms are still under development. Therefore, we are not sure that we will follow these solutions. Likewise, there was not a final decision about the transferred bids, so that it was not decided yet whether to transfer them untouched or to aggregate them.

Therefore, the fragmented market model with a market split between DSO and TSO is pretty straightforward to implement, whereas more precautions have to be adopted for the multi-level coordination scheme. Indeed, a risk could appear with the multi-level framework where the TSO could activate a bid with a counter-effect compared to the DSO previous action. To prevent this risk, a two-step process is planned to be implemented based on an optimization algorithm specifically designed for this purpose as detailed above.

6.4.3. Performance evaluation

After the brief overview on the mechanisms presented above, it remains to test their performance in order to be able to compare them in a fair way. This performance evaluation will be a quantitative one, based on a toy example. The first part of this subsection will present the representative toy example considered, then, the methodology pursued will be explained in more details through the presentation of the code structure and, finally, the quantitative results will be compared.

6.4.3.1. Presentation of the toy example

To assess the performance of the two coordination schemes introduced above and to benchmark them along the common market model, it is required to work on a common benchmark. To this aim, a similar analysis will be performed each time, thanks to the electrical network presented on Figure 22. This illustrative example is coming from the research conducted at UC Louvain [36]. It relies on a meshed transmission network in the middle composed of three nodes. Each one of these nodes is then connected to a distribution network composed of five nodes. As shown on Figure 22, all these three distribution networks adopt a radial structure. However, while the authors consider both active and reactive power in the modelling of their grid, a simplified network representation will be used, to focus on active power constraints only. The bid portfolio has also been adapted for the purpose of the present analysis. As a result, at the end of this pre-processing step, each node still includes either a local consumption or a local production.

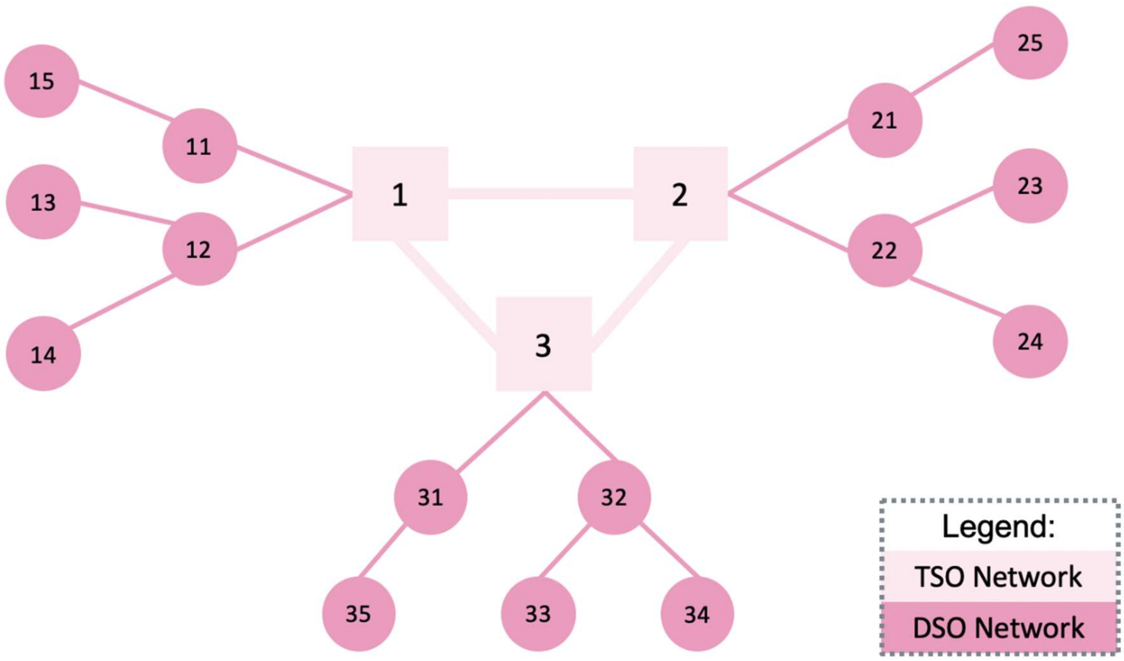


Figure 22: Network representation of the toy example used by the congestion management analysis

The idea behind this simulation is to set up first a day-ahead market without considering any network constraints, just trying to maximize social welfare among buyers and sellers of electricity. In a second time, closer to real-time, a second process is set up to deal with congestion management with the aim to resolve the issue in the most efficient way economically speaking.

The offer from generators and demand orders from consumers is summed up below[15] by [36, p. 4] :

> In summary, the system consists of two thermal units at the transmission level. The unit located in node 1 has a marginal cost of 10 €/MWh, and a capacity of 390 MW. The unit located in node 2 has a marginal cost of 20 €/MWh and a capacity of 150 MW. There is an inelastic demand of 350 MW in location 1. Each distribution tree has identical line characteristics and identical resources are connected to each distribution tree. Each distribution node is connected to a distributed aggregated producer of 85 MW and a distributed aggregated consumer of 80 MW. Aggregated flexible consumers with bid quantities of 50 MW and valuations ranging from 0 €/MWh up to 19.1 €/MWh are connected to each distribution node. Thus, each of the three distribution trees can offer up to 250 MW of upward reserve (if flexible demand is fully consuming), and each tree serves a price-inelastic demand of 400 MW. Zero-cost aggregated distributed production of 425 MW (which could also offer reserve) is connected to each distribution tree.

The toy example is used to illustrate the main differences between the coordination schemes for congestion management in the Greek demonstrator, in addition to discuss their challenges and processes. Formally, the following sequence of events is considered:

1. **Spot market**. First of all, a market runs and provides a first dispatch to the units. The characteristics of this market are that (1) it considers all the available units, (2) the initial dispatch of these units is assumed to be zero, and (3) it ignores all the grid constraints.

2. **Congestion management market(s)**. As the spot market ignores the grid constraints, its dispatch can possibly result in grid constraints violations which need to be restored by a so-called congestion management market. In a *Common Market Model*, this step corresponds to one single market which (1) considers all the available units, (2) which have an initial dispatch allocated by the spot market, and (3) considers both DSO and TSO grid constraints. For the *Fragmented Market Model* and for the *Multi-level Market Model*, there are:

    a) A DSO Congestion Management Market which (1) considers only the flexibility sources connected to the DSO grid, (2) which have an initial dispatch allocated by the spot market, and (3) only considers DSO grid constraints.

    b) A TSO Congestion Management Market which (1) considers either only the flexibility sources connected to the TSO grid (Fragmented Market Model) or all the units (Multi-level

[15] In addition, the full data of the model is given at the following address: https://perso.uclouvain.be/anthony.papavasiliou/public_html/Spider.dat

Market Model), (2) which have an initial dispatch allocated by both the spot market and the DSO congestion management market, and (3) only considers TSO grid constraints.

Of course, such a sequence is a simplification of what happens in reality within the Greek demonstrator, where congestion management can, for instance, come close to real-time, after multiple markets (long term, day-ahead, intraday, etc.). Nevertheless, from a conceptual point of view, it reflects well the situation to be analyzed: (1) the power unit starts from an initial dispatch of zero, (2) a set of markets, largely ignoring the grid constraints, provides a certain dispatch of the unit ending up in network violation which (3) drives the need of a congestion management market.

6.4.3.2. Code Structure

The AMPL code structure is presented in Figure 23 and reflects an implementation as close as possible with what was presented above.

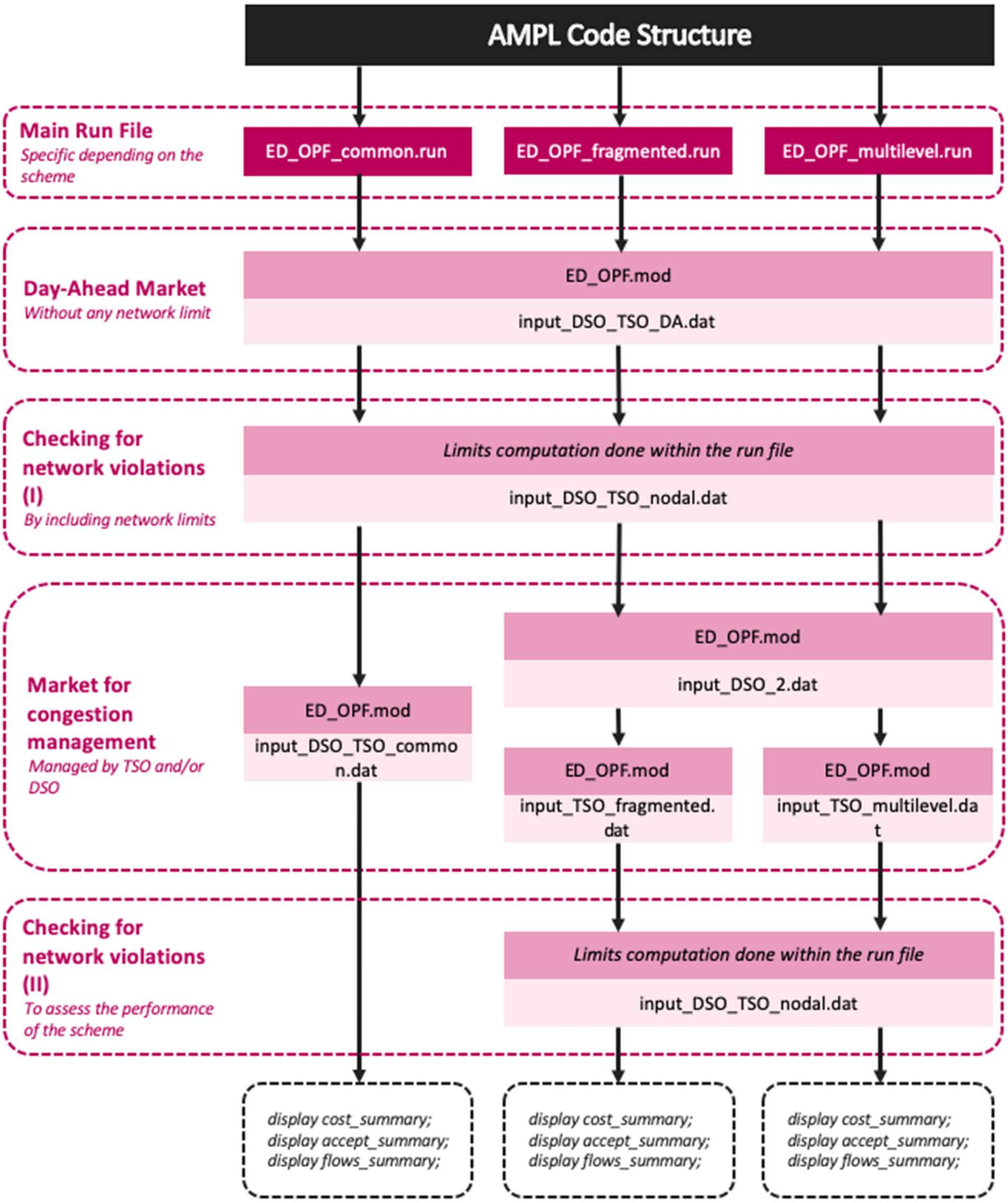


Figure 23: Overview of the Code Files, Inputs and Outputs Linked to the Congestion Management Analysis

As shown in Figure 23, each coordination scheme relies on its own *run* file. The *run* file coordinates the models and data that will be used at each step of the market simulation. For all simulations, a day-ahead market neglecting all network limits is run. In practice, it is done by setting the limits to huge values simulating infinity. Then, the network violations are measured by replacing the data used for network constraints with the real ones. Once this step is done, the market for congestion management takes place according to the coordination scheme principle presented before. At the exception of the common market model (which ensures by nature through the optimization model that the network limits will be respected), a second check of network violations is performed. The *run* files end by displaying the required results for our analysis.

Another interesting aspect remains to be addressed concerning the code organization. Indeed, each market is cleared with the exact same optimization model seeking to minimize costs. Only the data available for the model are changed each time to adapt to the required situation.

6.4.3.3. Main results obtained

In this subsubsection, all the relevant outputs are summarized for each framework of coordination. Then, a cost comparison is done before presenting the conclusion of the analysis.

Common Market Model

Table 22 reveals the performance of the common market model, by displaying the summary of accept ratios of all the bids submitted for trading. Each row is related to exactly one generator, as written in the first column. G_NX refers to the generator located at the node *X* from the transmission network, while G_nyz is the name of the generator from node number *yz* within the distribution network. The second and third columns of the table give the final activation ratio after the clearing of the market. To ease the reading, unchanged activations are highlighted in a lighter pink compared to the modified ones.

An important remark about the way to read the results in this table is the fact that the column related to the common congestion market reflects the *combined* activation of both the day-ahead market and the common congestion market. As an example, the first line reveals that the offer of the generator located at the Node number 1 (Transmission level) was accepted at 0.974359 by the day-ahead market and, then, it was cleared at -0.263176 by the common congestion market, i.e. to be finally accepted at a ratio of 0.711183. It is important to note this in order to compute properly the remunerations for the generators, and, therefore, the total cost to operate the system.

Table 22: Offer acceptance ratios of each generator over the successive markets in the case of a common market model

	Day-Ahead Market	Common Congestion Market
G_N1	0.974359	0.711183
G_N2	0	0
G_n11	1	1
G_n12	1	0.771765
G_n13	1	1
G_n14	1	1
G_n15	0	0.522353
G_n21	1	1
G_n22	1	1
G_n23	1	0.771765
G_n24	1	1
G_n25	0	0.522353
G_n31	1	1
G_n32	1	1
G_n33	1	1
G_n34	0	0.671043
G_n35	1	0.948235

For an illustrative purpose of the way the algorithm proceeded, Table 23 shows the evolution of the predicted flow over each line at each stage of the successive OPF processes, with each column referring to a market or an algorithm step. First, the expected network flow through each line of the network after the day-ahead market without considering any network limit is displayed. Then, the network violation check step is performed with a congestion check, to see when there are lines with an amount of flow predicted over the line limits. Finally, the common congestion market aims and achieves to solve this issue. As expected, as a double check to see if the OPF algorithm in the common congestion market performed well, it can be observed that the majority of (but not all) the flows over the lines previously congested are still reaching their maximum value. Likewise, by network effect and Kirchhoff's laws, some other lines without initial issue had their flow changed as well.

To facilitate the reading of the table, congestion problem values over the lines are surrounded by thick dark pink borders and unchanged values are still in a lighter pink compared to the modified ones.

Table 23: predicted flows over the lines of the network after the main steps of the algorithm with the common market model

	Day-Ahead	Congestion Check	Common Congestion Market
L1_2	126.54	126.54	92.3613
L1_3	243.46	**243.46 > 200**	200
L2_3	116.54	116.54	107.361
l111	-55	**-55 < -25.6**	-10.6
l121	45	**45 > 25.6**	25.6
l1312	15	15	15
l1412	15	15	15
l1511	-70	**-70 < -25.6**	-25.6
l212	-55	**-55 < -25.6**	-10.6
l222	45	**45 > 25.6**	25.6
l2322	15	15	-4.4
l2422	15	15	15
l2521	-70	**-70 < -25.6**	-25.6
l313	30	**30 > 25.6**	25.6
l323	-40	**-40 < -25.6**	17.0387
l3332	15	15	15
l3432	-70	**-70 < -25.6**	-12.9613
l3531	15	15	10.6

Anyway, at the end, all transmission line flows are within [-200 ; 200] MWh, while all distribution flows are included in the [-25.6 ; 25.6] MWh interval, leading the global network to be operated in a safe way in real-time.

Fragmented Market Model

Table 24 presents acceptance ratios of each bid after each market clearing. This time, black boxes were added to materialize the fact that transmission-level bids are un-usable in the DSO congestion market, while distribution-level orders are inaccessible in the TSO congestion market. Again, modified values are highlighted in a darker pink than the unchanged ones.

Table 24: Offer acceptance ratios of each generator over the successive markets in the case of a fragmented market model

	Day-Ahead	DSO Congestion Market	TSO Congestion Market
G_N1	0.974359	.	0.640719
G_N2	0	.	0.867465
G_n11	1	1	.
G_n12	1	0.315294	.
G_n13	1	1	.
G_n14	1	1	.
G_n15	0	0.522353	.
G_n21	1	1	.
G_n22	1	1	.
G_n23	1	0.522353	.
G_n24	1	1	.
G_n25	0	0.522353	.
G_n31	1	1	.
G_n32	1	1	.
G_n33	1	0.647059	.
G_n34	0	0.522353	.
G_n35	1	0.948235	.

A last remark remains to be addressed before moving to the last coordination scheme results. Obviously, a similar table as the one covering the network flows over each line in the common coordination schemes was created in the analysis, but it was decided to not include it here to sum up the results. As expected for this model, no congestion issues remain at the end, but it is achieved at the price of a higher cost as it will be covered during the comparison.

Multi-Level Market Model

Table 25 presents acceptance ratios of each bid after each market clearing. This time, black boxes were added only at the DSO congestion market level to materialize the fact that transmission-level bids are unusable in the DSO congestion market, while distribution-level orders are this time transferred to the TSO Congestion Market. The legend remains consistent with the other tables concerning the pink darkness, with modified values highlighted in a darker pink compared to the unchanged ones.

Table 25: Offer acceptance ratios of each generator over the successive markets in the case of a multi-level market model

	Day-Ahead	DSO Congestion Market	TSO Congestion Market
G_N1	0.974359	.	0.807289
G_N2	0	.	0
G_n11	1	1	1
G_n12	1	0.315294	1
G_n13	1	1	1
G_n14	1	1	1

G_n15	0	0.522353	0
G_n21	1	1	1
G_n22	1	1	1
G_n23	1	0.522353	1
G_n24	1	1	1
G_n25	0	0.522353	0
G_n31	1	1	1
G_n32	1	1	1
G_n33	1	0.647059	1
G_n34	0	0.522353	0.766558
G_n35	1	0.948235	1

Again, for this coordination scheme, it was decided to not include the full table with the expected flow over the network at each stage of the algorithm to lighten the main results presentation. In short, a new issue arises with this coordination scheme because some of the change of activations performed by the TSO congestion market clearing affect the flows over the distribution network, which ends up with congestions over the lines *l111*, *l121*, *l1511*, *l212*, *l222*, *l2521* and *l313*. As expected, it is still better compared to the day-ahead market because there is no remaining congestion at transmission level, but the results are quite poor to be implemented in practice for the DSO. This fact makes echo with the remark related to the Greek demonstrator, which showed that it was important to assess properly the remaining distribution bids transfer to the TSO market in order to avoid such issue.

Costs of each coordination scheme

Finally, Table 26 assesses the quality of each scheme in term of global costs involved during the successive clearings.

Table 26: Cost comparison between the different coordination schemes

	Common Market	Fragmented Market	Multi-level Market
Day-Ahead Market (€)	8135	8135	8135
Congestion Market 1 (€)	1232.79	1265.44	1265.44
Congestion Market 2 (€)		1301.20	-679.02
TOTAL (€)	**9367.79**	**10 701.64**	**8721.42**

The cost analysis of the different coordination scheme seems to be pretty straightforward: the multi-level coordination scheme appears to be the cheapest option here, before the common and the fragmented markets, respectively. However, it is important to remind that the multi-level market with bids transfer as was done in this analysis led to remaining congestion issue at the end of the day. It is therefore important to assess properly this transfer to benefit from this scheme in an appropriate but still advantageous way. Another point that is important to mention here is the fact that the common market (2nd best in terms of costs) was cleared by a common clearing program considering both DSO and TSO constraints at the same time. It is clear that it can be hard to achieve in practice if the system operators are not willing to share completely their data to the market operator or even to the other system operator. In that case, the performance in real life of the common market model could be poorer compared to these simulations.

6.4.4. Conclusions from the coordination schemes covered in the Greek demonstrator

To complete this analysis linked to the Greek demonstrator, a recapitulation through an outline of the main differences between the coordination schemes is presented next:

- The common market model is efficient (it uses all the bids) and results in a feasible setup (no constraint violation, as it considers all the constraints), but it demands a lot of coordination between the DSO and the TSO to be efficient.
- The fragmented market model is less efficient (it does not use all the bids), but it results in a feasible setup and demands less coordination between system operators.
- Regarding the multi-level market model, it is more efficient than the fragmented one, as it enables the TSO to access bids from the DSO, but if this transfer of bids between DSO and TSO is not done carefully, it can result in infeasibilities on the DSO grid. Roughly said, it demands more coordination between the DSO and the TSO than the fragmented, but less than the common market model.

Another point of attention of this kind of scheme – not covered by this analysis – is the gaming opportunity that may arise in this type of subsequent markets (see [37] for more details). This potential issue should be studied through game theory models and ideally based on past existing data.

7. Baseline methodology for congestion management- application for CoordiNet

In general, the baseline definition is mainly related to measurements of Flexibility Service Providers (FSPs), and the most studied programs so far are related to Demand Response (DR), which is defined in [38] as changes in electric usage by end-use customers from their normal consumption patterns in response to:

1. changes in the price of electricity over time,
2. incentive payments designed to induce lower electricity use at the time of high wholesale market prices, and
3. requests to support the system reliability when it is jeopardized.

Therefore, the measurement and verification of DR is the most critical component of any program. The baseline in DR could be defined as what the customer would have consumed in the absence of the demand response event [39]. Although baseline methodologies have been mainly exclusively used to refer to DR, the diversity of resources managed by small FSP require extending their application to a wider range of options, including customers with generation, storage and flexible loads.

Challenges that baseline methodologies should overcome are the following:

1. Non-available metering data of flexible providers:
    a. Non-available time-granular (e.g. hourly) individual metering.
    b. Not explicit requirement to send individual schedules (e.g. demand-side).
2. Aggregation and technical considerations of resources:
    a. Small resources.
    b. Different type of resources (e.g. loads, storage and generation).
    c. Interdependency between the consumption periods (e.g. demand-side flexibility, storage and generation).
3. Regulatory barriers:
    a. Limitation to aggregate resources from different types (e.g. demand, storage and generation).
    b. Agreements between retailers and third-party aggregators.
4. Implementation:
    a. Accounts for interlinks between markets.
    b. Manage coordination between agents (e.g. aggregators, retailers, DSOs, FSPs).
5. Integrity of the methodology:
    a. Avoid gaming possibilities that increase system service requirements or costs.

The main objective of this chapter is to develop the most suitable baseline methodologies for providing **congestion management** for the three demonstrators' countries of the CoordiNet project: Spain, Sweden and Greece.

The proposed methodologies, in addition to the challenges described previously, should consider the following specificities from the CoordiNet project:

1. They are initially applied to congestion management service, but further extension to other services is foreseen.
2. They consider the market design and coordination schemes defined for the CoordiNet demonstrators, as presented in the earlier sections of this documents.

A detailed review of the baseline methodologies is available in the Appendix D – Review of the baseline methodologies, while this chapter provides an evaluation framework for the assessment of the relevant baseline methodologies, in order to provide guidelines and recommendations of baseline methods for each demonstration campaign. To achieve this objective, a three-step approach is used. Firstly, a qualitative evaluation framework is constructed. This framework should be able to guide the evaluation of each baseline method relevant for the CoordiNet project. Secondly, the framework is put into use and each relevant baseline method is actually assessed, concluding on which baseline methods are expected to perform better in the given conditions. Finally, this evaluation is used to provide recommendations to the demonstration activities, specifically to the congestion management BUC, which is the focus of this deliverable. The characteristics of these BUCs in the three demo countries (e.g. product characteristics, market participants, market models) will be mapped within the space where the evaluation has been undertaken, providing indications on which baseline methods could be more appropriate for the BUC in each country. Figure 24 provides an illustration of the proposed approach used in the following sections.

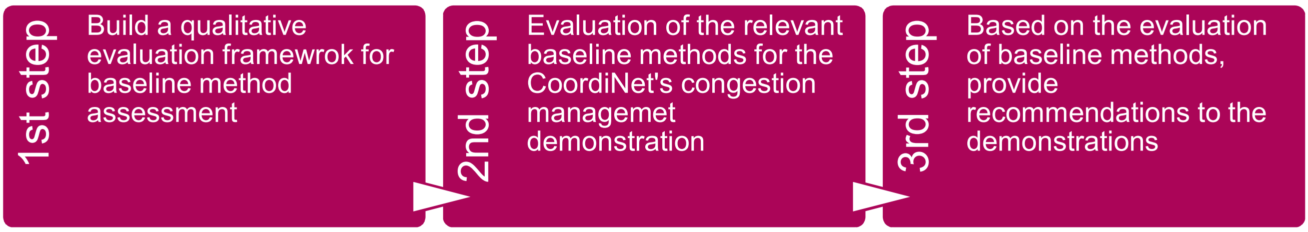


Figure 24: Overall approach for the evaluation of baseline methods and provision of recommendations to the demonstrators

7.1. The Baseline Evaluation Framework

The framework construction is based on the consideration of previous baseline evaluations found in the literature. Typically, baseline methods are evaluated in terms of their **accuracy**, **simplicity** and **integrity**. These criteria were firstly introduced by EnerNOC [40], and later used by other authors [32]. In order for a method to be accurate, the baseline computed should accurately estimate the level of consumption if the available flexibility is not activated. Besides, this method should be simple enough for stakeholders to understand and implement it. Additionally, the criterion **integrity** is used to determine to what extend a baseline method does not allow the FSP to game the system. A more comprehensive definition of these concepts is provided below. Finally, we also consider the **efficacy** of the baseline, meaning the alignment of incentives between the baseline and the congestion management program. Consequently, the starting point for the definition of the evaluation framework proposed are the aforementioned three **baseline assessment criteria**.

In addition to the general assessment criteria, it is also important to consider the conditions in which the baseline method will be used. For this report, these relate to the characteristics of the congestion management market, the market participants and, eventually, the TSO-DSO coordination schemes in place.

Considering the general baseline guiding principles and the characteristics of the congestion management schemes in the CoordiNet project, the framework proposed in this section can be represented in a three-dimension space, as shown in Figure 25. Axes are (I) 'X': the possible baseline methods, (ii) 'Y': the assessment criteria for baseline determination and (iii) 'Z': the applicable market, product and agent characteristics, making the context where the baseline method will be used.

Each baseline method will be qualitatively assessed according to each assessment criterion (see the XY plane in the figure). Besides, the suitability of each baseline method will be assessed in terms of each market characteristic (see the YZ plane). The former type of assessment is partially covered by the literature on baseline methods, as referred later in this section. The assessment in the XY plane concerns the performance of each baseline method according to each relevant criterion. Finally, the assessment in the XZ plane will not be considered, since the features of the market in each use case is taken as given. Therefore, this assessment is not relevant for the presented analysis. Besides, the relationship between the categories defined in these two axes is not always clearly defined, which involves that clear conclusions cannot always be drawn. The considered assessment criteria cannot be used to evaluate the market characteristics applicable in each BUC.

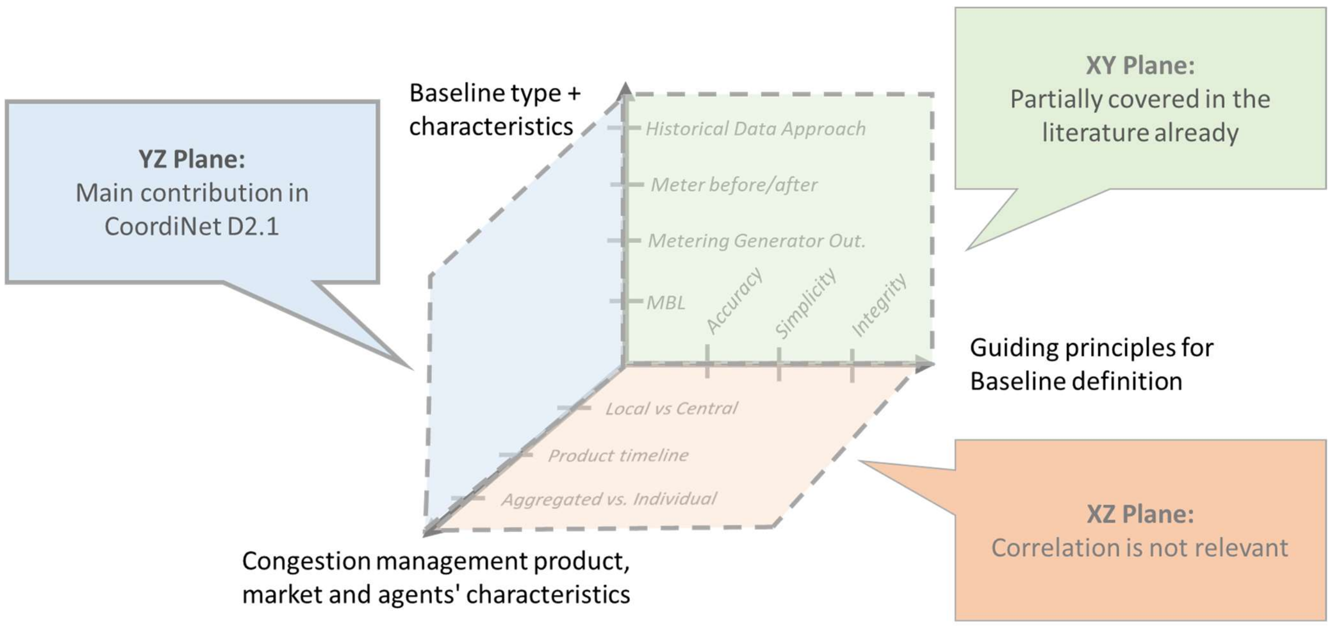


Figure 25: Framework concept for the evaluation of baseline methods

The following subsections detail the exact baseline methods (Y axis), the assessment criteria (X axis) and market characteristics (Z axis) to be considered in the analysis.

7.1.1. Baseline Methods and Characteristics (The Y Axis)

The Y axis is composed of potentially relevant baseline methods for the CoordiNet demonstrations and incorporates the relevant characteristics of each baseline method. As shown in the Appendix D – Review of the baseline methodologies, several baseline methods are defined in terms of certain design parameters. For instance, the popular "High X of Y" method is a variant of the "X of Y" method, often shaped by its exclusion rules, the existence of adjustments to reflect the consumption level at the day of the activation and the length of the X and Y periods. The value of these parameters also influences the performance of the baseline method with respect to the assessment criteria (X axis) and also with respect to its suitability for markets with certain characteristics.

Table 27 below lists the chosen baseline methods and their characteristics considered in the analysis. Firstly, historical approaches are considered, as they are commonly used in several countries and, according to the literature, provide a good balance between simplicity, accuracy and integrity. Among the historical approaches, the most used one is the "X of Y" method, as mentioned above. Within this method, however, several parameters have to be considered together with the method itself. Therefore, considering its importance and dependence on the values given to the several parameters associated with it, the X of Y method is assessed from the perspective of several different parameters related to it, such as the look-back window, the exclusion rules applied within it, the type of X considered (e.g. high X of Y, mid X of Y, etc.), and the several possible baseline adjustments to be made close to delivery.

Still within the category of historical approaches, other baseline methods are also important, namely the regression method, the comparable day and the rolling average ones. These methods are less dependent on design parameters than the “X of Y” method. The regression approach may consider different explanatory variables (e.g. time of the day, season, weather etc.), but the choice of these variables is made with the objective to maximize the fitness of the regression model. Therefore, the independent analysis to be made of the parameters for these methods is reduced.

Apart from the historical data approach, three other methods are considered. Firstly, the maximum baseload, including the coincident and non-coincident variants of this. Secondly, the “meter before / meter after” is also included, as this is a simple method that could be efficient to deliver very short time-period products (congestion management could be one of them). Lastly, the “metering generator output” is considered, as this method can be relevant for the case in which behind the meter DG exists.

It is worth mentioning that the “statistical sampling” method was left out of this analysis. This method is used when not all consumers are provided with a smart meter, and therefore statistical inferences have to be done. This does not seem to be the case in the CoordiNet countries, as Spain and Sweden already completed the deployment of smart meters and Greece is expected to achieve a large-scale rollout by 2020 [42]. More specifically, the resources considered in the demonstration campaigns are expected to have the appropriate measurements and communication equipment for the baseline calculation.

Table 27: Baseline methods considered in the analysis

Baseline Methods		Design Element
Historical data approach	X of Y	Look-back window (Y days)
		Exclusion Rules
		Relationship between X and Y (High X? Mid X?)
		Baseline adjustment
	Regression	Explanatory variables
	Comparable day	-
	Rolling average	Number of days
		Weighting of days
Maximum base load		Coincident
		Non-coincident
Meter before/meter after		-
Metering generator output		-

7.1.2. Assessment Criteria (X Axis)

The criteria traditionally applied for evaluating baseline methodologies are accuracy, simplicity, and integrity. These criteria were already use and described in several academic papers and reports from the industry [39]-[41], [43]:

1. **Accuracy:** Customers should receive credit for no more and no less than the service they provide, so a baseline method should use available data to compute an accurate estimate of the baseline level. Accuracy, in this case, means the capacity of estimating the consumption level that would have been used if the flexibility had not been provided. In theory, it should neither underestimate the baseline (lower incentives for flexibility providers), nor overestimate it (higher cost for the flexibility procuring party).

2. **Simplicity:** The baseline method should be simple enough for all the stakeholders to understand, calculate and implement it, including the end-use consumers. Besides, it should be possible to determine the baseline in advance of, or during, the activation of the service, so that it can be used to monitor curtailment performance in real-time. Therefore, a baseline method should be technically implementable, considering **(1) data availability, (2) data exchange needs,** and **(3) computation time required.**
3. **Integrity:** A baseline method should not include attributes that encourage, or allow, consumers, or other FSP in general, to distort their baseline through irregular consumption, nor allow them to game the system.

In addition to these criteria, another guiding principle is included in the proposed framework, namely the efficacy of the baseline.

4. **Efficacy:** the chosen baseline methodology should minimize unintended consequences, as inadvertently penalizing real curtailment efforts [40]. Baseline methods will inevitably be imperfect and, therefore, it is important to consider which incentives possible errors in their implementation, or management, will give to flexibility providers.

7.1.3. Market, Product and Agent Characteristics (Z Axis)

The last dimension tries to capture the most significant aspects of the design and the conditions of the market where the baseline will be computed and considered in congestion management. More specifically, the characteristics of the possible congestion management market designs in the CoordiNet demonstration campaigns are to be taken into account. It is also important to consider the market conditions, such as the type of agents that will participate in these markets. Table 28 below lists the chosen market design, product and market participant aspects that are considered in this analysis.

With regards to market participants, distinctions are made between aggregated vs. individual FSP, type of flexibility providing unit and procuring agent. On the market design side, product timing and the market coordination model are considered.

Table 28: Market design and market participant aspects

Characteristic	Description
Agents / Trading type	Aggregated
	Individual
Type of Unit	Baseline for specific DER types
	Baseline for the combination of DER types under the same FSP
Market / product timing	Capacity vs. Energy
	Activation notification / Delivery duration
Market model	Common
	Distributed
	Fragmented
	Multi-level

7.2. Evaluation of Baseline Methods According to the Assessment Criteria (XY Plane)

In this section, the variants of each baseline method are described and then evaluated with respect to each of the assessment criteria previously described. The seven selected baseline methods are evaluated according to the four assessment criteria, namely accuracy, simplicity, integrity and efficacy.

7.2.1. Historical data approach – X of Y

The “X of Y” variant of the historical data approach is a common baseline methodology, used in several countries, as shown in subsection 14.1.5. This method is often chosen because it strikes an appropriate balance among the three original evaluation criteria, namely accuracy, simplicity and integrity. Nevertheless, the overall performance of this method will depend also on the definition of its parameters.

The X of Y methodology involves averaging the level of demand/generation over X days in the last Y eligible days. The X days should be selected to best represent the event day (resource activation). A common variation of this method is the “High X of Y”, which considers the X days with highest consumption in the Y-day set. This is done for two reasons. Firstly, demand response programs will usually call for consumption reduction from consumers on days with very high consumption. Secondly, the High X of Y also minimizes the risk of unintended incentives that could result from underestimating the baseline. If a DER is presented with an underestimated baseline, incentives for curtailment are lower, as the possible gains for the consumer will be reduced. The “Middle X of Y” variant could be appropriate for products that are not completely linked with peak load hours, for instance [43]. In the context of congestion management products though, in general, a correlation exists between peak load and the service being activated[16]. Therefore, for the purpose of congestion management products, High X of Y should be considered.

The number of days in both the X and the Y sets is also an important parameter to be defined. First, it is necessary to define the look-back window, or the Z set of the last calendar days. Once the Z set is defined, exclusion days should be left out, in order for the last Y set of eligible days to be selected. From the Y set, the X days with the highest consumption can be used to calculate their average level as the baseline. Exclusion days are usually weekend days, holidays and event days, when a previous activation took place, although additional fine-tuning criteria can be implemented [43].

[16] This correlation is the general case. Congestions here are understood as the violation of the thermal limits of the elements in the network, which should occur more often in high-demand periods. This is different from balancing service needs, for instance, that do not have a general origin in peak consumption, but rather on the mismatch of scheduled units. Nevertheless, even for congestions, it is possible that the causes are not associated with peak load. For instance, in meshed network, certain elements can become constrained eventually for reasons other than excessive generation.

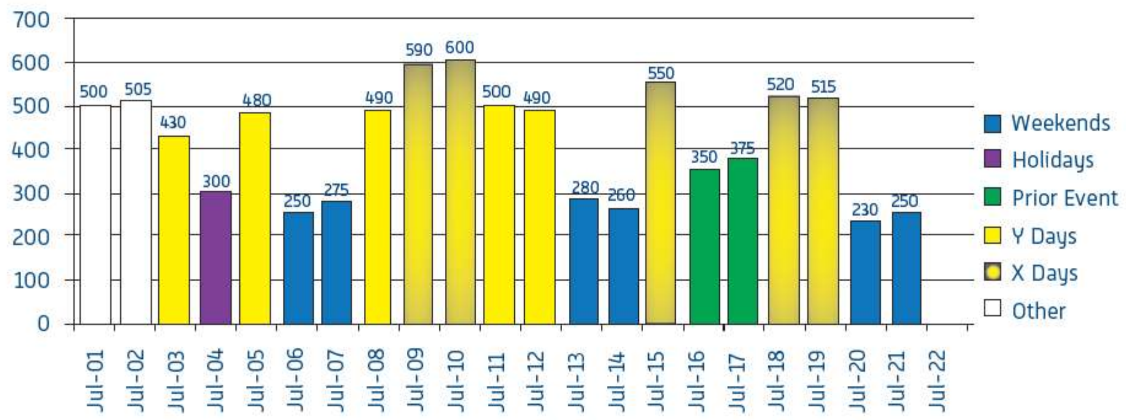


Figure 26: Example of a High X of Y baseline calculation, [43]

Finally, once the average High X of Y is calculated, an adjustment can be made to consider the difference in consumption between the event day and the average day within the X set. The adjustment will typically consider a time window of some hours before the provision of flexibility and can be done in a scalar or an additive manner. The former compares the average baseline with the consumption on the time window prior to activation and adds the percentual difference for each time period in the activation period, while the latter calculates the absolute difference in kW, and adds it to each time period (a fixed kW value).

Considering the several design parameters of the X of Y methods, it is possible to identify which elements of the baseline method may enhance, or may hamper, the baseline's characteristics in terms of accuracy, simplicity, integrity and efficacy. Firstly, considering the congestion management product, and therefore a service that is associated with high peak loads, a High X of Y could provide higher accuracy, considering that it takes into account the days with highest consumption, as opposed to a "low" or "middle X of Y". Also, this variant has higher efficacy, as it mitigates the risk of underestimating the baseline and, therefore, reducing the incentives for flexibility provision. In terms of simplicity and integrity, this parameter alone does not impact the method performance.

As the look-back window becomes longer, accuracy could be affected. With a longer Z set of days, outdated consumption information can be included in the baseline calculation, as weather and consumption patterns change.

The adjustment type and if the adjustment is capped or not can play an important role in the performance of the baseline method. Capping the adjustment has the advantage of improving integrity, as the possibility for the flexibility provider to change the level of consumption hours before delivery to inflate the baseline is minimized. On the other hand, capping the adjustment can potentially reduce accuracy, and mainly efficacy, as it may lead to underestimated baselines. In such cases, the consumer may be left with weak incentives to provide flexibility.

Another important aspect of the baseline adjustment is the type of adjustment, either additive or scalar. Scalar adjustments could lead to inflated baselines if the adjustment is calculated during low consumption periods [43].This characteristic could increase the opportunities for gaming.

Across the different design parameters considered, one aspect that does not seem to be affected significantly is simplicity. For all their variants, the X of Y baseline methods are simple to communicate and data requirements to implement them are not excessive. These data requirements are mostly related to metered data from the past Z days (usually 30 to 60 days).

Table 29 below presents a summary of how the different design parameters of the X of Y method impact its performance according to the assessment criteria, where a (+) sign represents a positive effect of the parameter with respect to the principle, a (-) a negative effect and neutral means that the design is neutral with the principle. These impacts are determined in relative terms to compare them to those for the alternatives regarding the same design parameter.

Table 29: Effects of the different X of Y design parameters on the assessment according to the assessment criteria

X of Y Design Parameter		Accuracy	Simplicity	Integrity	Efficacy
X of Y variant	High X of Y	+ for peak load related events	Neutral	Neutral	+ as it will not underestimate baseline
	Middle X of Y	- for peak load related events	Neutral	Neutral	-
Y length	Long look back window	-	Neutral	Neutral	Neutral
Type of adjustment	Scalar Adjustment	- as baseline becomes more volatile	Neutral	- as consumers will have more incentives to inflate consumption prior to activation	Neutral
	Additive Adjustment	+	Neutral	Neutral	
Capped vs. Uncapped adjustment	Capped Adjustment	- as consumers may be penalized in days of extreme demand	Neutral	+	- as underestimating the baseline limits incentives for demand reduction
	Uncapped Adjustment	Neutral	Neutral	-	Neutral

From an overall perspective, considering a High X of Y method with uncapped additive adjustment, few conclusions can be drawn regarding to its performance in terms of the assessment criteria. Firstly, quantitative studies tend to point that the accuracy of the X of Y method is low or acceptable, but not optimal. Jazaeri et al. [41], for instance, concludes that the accuracy of a High 5 of 10 is low when compared to more complex methods, such as regression, polynomial interpolation and machine learning. EnerNOC [44] concludes that, in terms of median percent errors, a High 4 of 5 adjusted baseline performs better than other averaging techniques, but still with a -10% to 10% error. Regarding simplicity, as mentioned, it is safe to say that this method is simple to apply and easy to be understood by stakeholders. Regarding integrity and efficacy, the performance of the method depends on the final setting of design parameters. For an uncapped additive adjustment setting, the risk of gaming could exist, and, in this case, additional fine-tuning rules for the adjustment could be put in place, such as the possibility of considering more exclusion day rules. The efficacy of the X of Y is expected to be appropriate, as the baseline is not often underestimated.

7.2.2. Historical Data Approach – Regression

Regression baseline methods take an extensive data set as input and determine the relationship between a dependent and independent variable(s) through a regression model. To understand its performance in the XY plane, the methodology is examined in terms of the assessment criteria.

First, concerning the accuracy, regression approaches use sophisticated statistical tools to calculate the baseline, and they are proven to be more accurate in the literature, because they take into consideration many variables that influence load. However, in some regression techniques the accuracy may be badly affected if the consumption behaviour of the consumers changes significantly in the training set period compared to the test period (e.g. installing PV panels or batteries) [41]. Moreover, if observations do not include conditions as extreme as the curtailment day, the model estimate may be inaccurate.

Second, from the simplicity viewpoint, this baseline is more challenging to communicate due to its complex calculation process. For instance, to compute the ERCOT-Regression baseline (paragraph 14.1.5.1) the model considers calendar variables (e.g. day of the week, holiday indicators, season), weather variables (dry-bulb temperature and various functions thereof) and daylight variables (e.g. daylight saving time, times of sunrise and sunset), among others. Furthermore, [40] reports that regression approaches are less hospitable to stakeholders, which makes understanding the link between their actual curtailment efforts and the performance for which they are credited more difficult.

Third, in terms of integrity, the regression baseline has a very small chance of being artificially modified by consumers, because a regression analysis is complex. For example, it uses a long historical dataset and artificially increasing load for a few days will not change the outcome of the regression model significantly. Therefore, the opportunities to game the system are minimized. Finally, to analyse the efficacy of this approach, we have to consider that the purpose of the regression model is to provide a reliable estimate of what the load for a particular consumer would have been on a particular day in the absence of a control event. Inaccuracies for an individual consumer and event have financial consequences for the consumer, and, in the long run, may affect the consumer’s willingness to participate in a demand response program [45].

To sum up, regression approaches sacrifice too much simplicity by accuracy. However, they perform well regarding the integrity and efficacy criteria. Table 30 gives an overview of the qualitative evaluation of the regression-based baseline method in the plane XY.

7.2.3. Historical Data Approach – Comparable day

The comparable day baseline method identifies a representative day in the past, to be taken as a reference for the computation of the baseline, using historical meter data. Therefore, this process is simple to communicate. For instance, match-day criteria based on load or temperature can be used to select days with similar load characteristics. Clearly, this approach only works to the extent that such comparison days exist. Then, comparable day approaches require a sufficiently large pool of days to select from, so that comparable days are likely to be found. Match-day criteria will be inappropriate during the first heatwave of summer, unless either the previous summer load is available for consideration, or the baseline calculation can be deferred until more summer data are available. However, any extension of the overall time span from which data can be drawn increases the possibility of structural changes affecting the accuracy of the baseline [45].

Finally, while other approaches allow the authorities to calculate the baseline in advance, here the selection of the comparable day relies upon after-the-fact identification. Thus, it is not possible to know the baseline level during the event, which could impede meeting the curtailment goal. This makes it difficult to assess the efficacy of this method. In brief, the lack of objective criteria for the selection of the comparable day negatively affects the performance of the comparable day baseline method. Besides, if the flexibility provider is responsible to select the comparable day, there is a risk that he will modify this in its own benefit, which affects negatively the integrity of the method. This assessment is summarized in Table 30.

7.2.4. Historical Data Approach – Rolling Average

In general, the rolling average baseline method uses historical meter data from many days, but it gives a larger weight to the most recent days. To evaluate the performance of the rolling average in the XY plane, the following arguments are highlighted. A summary is included in Table 30.

Regarding accuracy, since this baseline method relies on a large number of data points, it could have a high accuracy for a consumer who has similar load patterns and levels throughout the year. However, the level of performance depends upon having sufficient data to reflect representative conditions.

From a simplicity perspective, this method is not complex to apply. For example, the calculation of the New England (ISO-NE 90/10) baseline, which employs this methodology and is mentioned in paragraph 14.1.5.1, depends on the type of consumer. For instance, if a consumer is a new participant in a DR program, the baseline considers the hourly average of the previous five business days, excluding holidays and other event days. This average is known as “Customer Baseline 6”, where the “6” refers to the day following the previous five business days, or the sixth day. Once the “Customer Baseline 6” has been calculated, that customer is considered a current customer, and the baseline is computed using the following formula:

$$\text{New Baseline}=\text{Previous Days Baseline}*0.9+\text{Current Day Metered kW}*0.1$$

Therefore, this new baseline method assigns a weighting factor of 90% to the previous days and a weighting factor of 10% to the current day, and it is computed every day except weekends, holidays and event days. Moreover, in terms of integrity, by putting more weight on the previous days, this calculation method reduces the potential to be gamed by customers.

On the other hand, in terms of the efficacy, the rolling average may not be the best method for customers whose energy fluctuates between seasons, because the calculation of the baseline in one season could reflect the usage of the previous season, and might be too low for the customer to receive any credit for curtailment [43]. Similarly, for loads whose load level repeats every certain number of days the rolling average is not appropriate, unless the periodicity of load is considered in selecting the days of the rolling window.

7.2.5. Maximum Base Load

As stated in section 14.3, the Maximum Base Load (MBL) method is a static baseline method that identifies the maximum energy usage expected of each customer and, then, sets a specific level of electricity usage that is equal to the maximum level, minus the committed capacity of the customers. This technique uses historical meter data to obtain the MBL considering previous year’s peaks, either coincident or non-coincident. For example, coincident uses peak hours that are chosen based on system load peaks, and a non-coincident baseline also uses peak hours, but they are determined according to the individual load behavior and not by the system load. It is worth mentioning the following comments about the performance of MBL in the XY plane.

First, the MBL baseline method is straightforward and simple to implement, given that it only requires to be computed once a season. It is entirely possible for a customer to provide the service by doing nothing at all, as long as its load is already at or below the “drop to” level. For example, in subsection 14.3.2 the Average coincident load (ACL) used in the NYISO, and Peak load contribution (PLC) in PJM, were described. Both baseline methods identify the peak hours of the previous years and then use the load on those hours to create an average maximum load for each customer. Therefore, this maximum load becomes the baseline for all hours of the current summer.

Second, according to existing analyses, the MBL method features poor accuracy. For instance, the accuracy of MBL and High X of Y baselines was analysed in terms of the metric median percent error (Median Percent Error = ($Baseline_{h1}$ - $Meter_{h1}$) / $Meter_{h1}$). Results revealed that both MBL baseline methods overstate meter load and have high variation in errors. This study estimates a 5% over-bias for the coincident MBL, and a 30% over-bias for the non-coincident MBL. Moreover, both MBLs have a high variability in the median percent errors. Figure 27 illustrates the outcomes of the analysis, where the main conclusion is that the High X of Y baseline methods exhibit higher accuracy and lower variability compared to the MBL baseline methods.

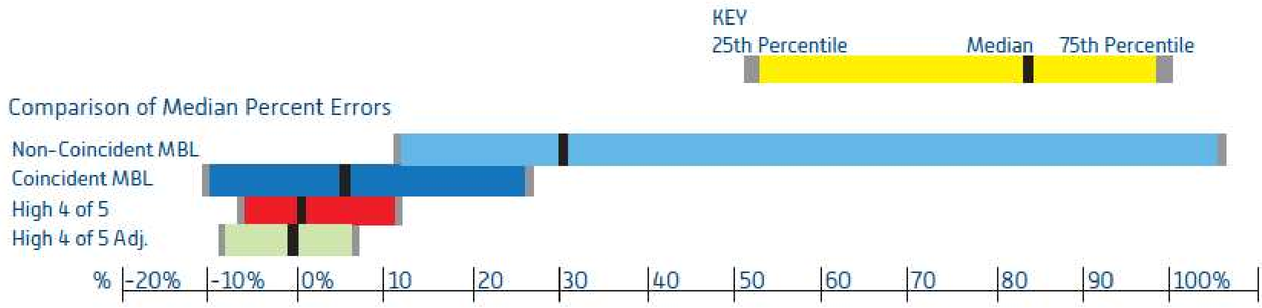


Figure 27: Accuracy comparison between MBL and High X of Y baselines, [43]

Third, from an integrity perspective, the MBL baseline methods provide little opportunity for participants to distort their baselines, given that this method is based on peak values selected from extensive data. Finally, in terms of efficacy, non-coincident peak days set the baseline artificially high, which allows the baseline to almost always be higher than load and, thus, a baseline based on non-coincident peak days will overstate performance. Table 30 summarizes the evaluation of the MBL baseline methods according to the previous comments. Furthermore, the below recommendations regarding the use of MBL methods are compiled:

1. Some customers have volatile loads, but they are enrolled in a DR program because they can easily curtail large amounts of energy usage. For these customers, a baseline based on historical data approaches will not be able to accurately forecast load. Therefore, it is better to use a MBL technique to set the baseline and expectations for curtailment [43].
2. DR programs that are intended to ensure that loads do not exceed levels used for planning, and for which real-time load reductions are irrelevant, suit well MBL methods, since these are more appropriate for ensuring that load stays at or below a set level [43].
3. Where an MBL method is more appropriate, a coincident baseline should be used, because non-coincident baselines drastically overstate performance in comparison to coincident baselines and other historical data approaches.
4. MBL approaches are often preferred for verifying the contribution of DR to capacity commitments [39].

7.2.6. Meter Before / Meter After

The meter before / meter after (MBMA) method is a static baseline method, which is usually employed for fast-response programs and reflects actual load changes in real-time, reading the meter before and after response to measure the change in demand. The main argumentations related to its qualitative evaluation in the XY plane are described next.

In terms of simplicity, the concept of MBMA is relatively easy to communicate and apply. However, this baseline method can be subject to gaming by the customer offering DR services. For example, a consumer could artificially increase its demand on a high peak day in order to reap a higher value for then decreasing its demand.

In terms of accuracy, the MBMA method may prove to be an appropriate method for accurately estimating the response of DR resources in real-time dispatch conditions. Similarly, as stated in section 14.4, MBMA baseline methods are favoured when dealing with system services, in particular frequency regulation. Clearly, MBMA should be applied to demand resources with relatively flat load profiles during the time period of the dispatch. If a resource has periods of ramping up or down, or general variability, the MBMA approach can over- or under-estimate the actual level of load reduction even for a short period [46].

7.2.7. Metering Generator Output

According to section 14.5, the Metering Generator Output (MGO) method is used when a generation asset is located behind the DR's revenue meter, where the demand reduction value is based on the output of the generation asset. The performance of MGO method in the XY plane is evaluated below and a summary is included in Table 30.

The methodology and the application of MGO method are straightforward to communicate, so to explain its functioning Figure 28 presents two meter-configurations. On the one hand, configuration A includes a net meter (N) which denotes the net effect of the load being offset by the behind-the-meter generation, or another device, such as a battery storage one. In this scheme, there is no way to separate the load from the generation or vice versa, and it is not possible to identify the cause of DR behind the meter. On the other hand, configuration B incorporates a generation meter (G), so the pure load could be obtained as the difference (N-G). Here, three possible options could be analysed [47]:

- Option B1 (load reduction only), where the DR performance would be estimated using a baseline (B) obtained from N-G values for comparable non-dispatch hours.
- Option B2 (Generation offset only), where the DR performance would be estimated based on the level denoted by the meter (G) for the dispatch interval.
- Option B3 (Load & Generation), where the DR would be estimated using a baseline determined considering both the level N-G and the level of G.

The Option B2 is also referred as the "zero baseline". The baseline is effectively zero, and any generation by the DG measured by meter G is considered as "demand reduction" for the purpose of determining the level of the system service.

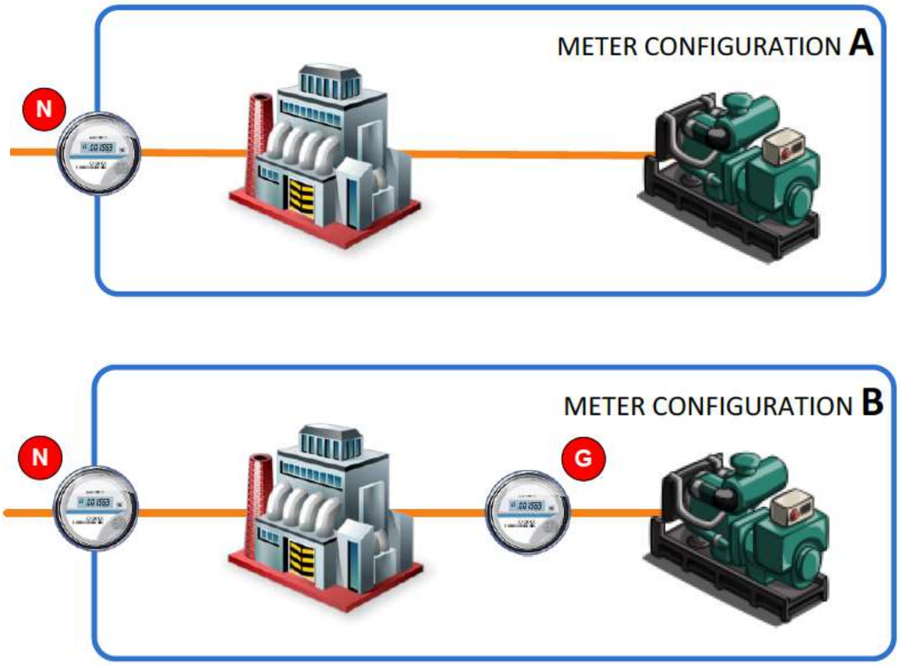


Figure 28: Load offset by behind-the-meter generation, [47]

Regarding the accuracy criterion, one drawback in configuration A is that a resource that relies on a behind-the-meter generator or device used frequently may have an unpredictable load profile. This will cause the inability to derive a reasonable, predictable baseline-load profile to determine performance during a system service activation. According to [47], in the option B2 (MGO) may not be able to differentiate between the generation device's retail activities (DG generating to offset some portion of the load's consumption to reduce the load's peak demand charges) and its wholesale activities (receiving a dispatch instruction from the system operator). Therefore, it would be problematic for the wholesale market to pay for activation when the resource is generating to reduce a customer's demand charges, because the grid would experience no true demand response/load modification. One possible solution is that the generation device "reserve" a portion of its capacity for retail activities and the remaining portion for wholesale purposes [47].

In terms of efficacy, the "zero baseline" method could be considered the least efficient, as it only provides incentives for the DG generation and not for demand reduction. In fact, this baseline could be combined with another baseline method, described as Option B3 above, providing a more appropriate incentive for both DG and load reduction. Another aspect to be considered is the fact that this baseline method requires another meter to be installed, increasing complexity and cost of implementation.

Table 30: General evaluation of baselines methodologies regarding XY plane

Baseline	Accuracy	Simplicity	Integrity	Efficacy
X of Y	*Medium*	*High*	*Medium*	*High*
Regression	*High*	*Low*	*High*	*Medium*
Comparable day	*Medium*	*High*	*Medium*	*Neutral*
Rolling Average	*Medium*	*Medium*	*Medium*	*Medium*
Maximum base load	*Low*	*High*	*Medium*	*Medium*
Meter before/meter after	*Medium*	*High*	*Low*	*Neutral*
Metering generator output	*Medium (depending on option)*	*Medium (another meter required)*	*Medium*	*Medium*

7.3. Baseline Evaluation with Respect to Congestion Management Market characteristics in CoordiNet (YZ Plane)

According to the evaluation proposed in this deliverable, this section looks at the fitness of the different baseline methods for their implementation in the context set by the different congestion management market design options, different congestion management products and market participants. These considerations are important in the context of the CoordiNet project, as the merits of a baseline method, being considered for its implementation in a particular market with some specific features, may not be the same as those highlighted in the literature.

Typically, the baseline literature assumes the baseline to be the estimated **consumption** that would take place in the case where **demand response** is not activated. Therefore, the baseline is defined for a consumer that participates in load reduction program. In the case of CoordiNet, the focus is not the same. The baseline must correspond to the estimate of the overall agent's electricity balance (considering generation and/or consumption) for all those **units that are not individually scheduled**. In this context, we refer not only to consumers alone, but also to prosumers, and to small distributed generation.

In European energy markets, units participating in wholesale markets already have a schedule that also serves as a verification tool for other system services, such as balancing, for instance. Large generation units are commonly scheduled individually, which could also be the case for large industrial consumers. For smaller consumers, however, scheduling does not happen at the individual level. Retailers are responsible for an aggregated schedule of consumption of all clients, but individually these clients have no commitment to any schedule. Therefore, if these smaller customers are to participate in the congestion management markets of CoordiNet, a baseline is needed.

The characteristics of congestion management products may also contribute to the complexity of the baseline definition. Differently from balancing markets, for instance, congestion management markets can be cleared several days, weeks or even years ahead of real-time. Products can also vary, possibly being capacity or energy, and could have a variety of duration periods as well. Moreover, an additional complexity within the demonstration projects is the fact that several system operators may be the responsible for procuring the flexibility. Besides, often, the party responsible for metering is not the same as the party procuring the service.

7.3.1. Different baseline methods for different types of DER

Most baseline methods discussed in Appendix D – Review of the baseline methodologies, and implemented in several countries already, were developed with the focus on the consumer, who participates in a load reduction programme. However, as mentioned above, not only consumers will participate in the CoordiNet demonstration, but also distributed generation and storage facilities, not only in isolation, but also combined (e.g. residential consumer with PV behind the meter). In addition to the different types of DER, it is also important that the size of a given unit may also suggest different characteristics in terms of energy usage, and therefore should be considered when choosing a baseline method.

7.3.1.1. Baseline for specific DER types

Considering consumers, most baseline methods are suitable. Historical approach methods are appropriate, as consumers tend to have a stable to some extent predictable load curve. The maximum base load and the meter before/ meter after, are mostly suitable to any type of DER, considering their intrinsic simplicity. The only baseline method clearly not applicable to consumers is the "zero baseline", as this method is designed towards distributed generation behind the meter of a consumer.

On the side of distributed generation, a differentiation has to be made between the controllable and the non-controllable DGs. The non-controllable units are mainly wind generators and PV units. For this case, the size of the units is also relevant. For utility-scale PV and wind farms, it is possible that they are already scheduled in energy markets, not requiring a specific baseline for other services. However, if these units are at the consumer scale, a baseline is needed. Not all baseline methods would be applicable in this case. Averaging methods, such as the "High X of Y" or the "Rolling average" are not suitable, as the output of these units are not correlated to past generation, but to other aspects such as weather conditions. In this sense, regression could be used, if an appropriate model and data are used.

In the case of controllable DG, two types should be distinguished. On the one hand, backup generators associated to a consumption unit can be used to provide services. On the other hand, CHP units could also be used. These two units are not the same in terms of generation patterns. The first one is not expected to generate electricity constantly, and the most appropriate baseline is the metering generator output. With regards to the CHP, generation patterns should be more stable, and historical methods could be considered.

Finally, the last type of DER to be considered is storage, more specifically batteries. This type of DER has characteristics of both consumption (charging mode) and controllable distributed generation (discharging). If treated separately from the other DER of the delivery point, historical data approaches may not be accurate for this type of DER, considering that the batteries' behaviour could be linked to other factors, such as PV generation (if they are installed together) or response to dynamic tariffs. In this case, meter before/meter after could be used. However, to reduce the potential for gaming, a floor can be introduced, according to the direction of the flexibility being provided. For example, if the flexibility provided is upwards, the battery would have to be in the discharging state, either providing electricity behind the meter and, therefore, reducing consumption, or injecting directly into the grid. In such case, the baseline could be set as meter before / meter after, but with a limitation on the meter before to zero. That is to say that the battery cannot be in charging state during the "meter before" timestep to profit from the big difference between charging / discharging. The same rational is valid for the downward flexibility, or the charging state of the battery.

Table 31: Baselines methods for different types of DER

Baseline Methods		Consumers, Heat pumps	PV and Wind	Backup generation	CHP	Storage, Batteries
Historical data approach	High X of Y	*High*	*Low*	*Low*	*Medium*	*Low*
	Regression	*High*	*Medium*	*Low*	*Medium*	*Low*
	Comparable day	*High*	*High*	*Low*	*High*	*Low*
	Rolling average	*High*	*Medium*	*Low*	*Medium*	*Low*
Maximum base load		*High*	*High*	*Medium*	*High*	*Medium*
Meter before/meter after		*High*	*High*	*High*	*High*	*High (with adaptations)*
Metering generator output		*Low*	*Low*	*High*	*Low*	*High*

7.3.1.2. Baseline for combined DER types

In the case of an active consumer with distributed generation behind the meter, the main concern is related to the volatility that DG may add. In fact, in this case, the consumption pattern, or overall grid withdrawn from the grid, is impacted not only by the consumption needs of the consumer (e.g. associated to weather conditions), but also by the generation of their DG installation. These are two aspects that usually have no correlation. Figure 29 exemplifies what would be the baseline computed for a prosumer with a PV installation behind the meter and for one prosumer without it. In the case of no DG, the baseline is estimated and, after the delivery of the services, the FSP is paid the area "A" in Figure 29. In the second case, with PV generation, the baseline would be computed having to deduce from the gross 'expected' consumption the generation of the PV installation, represented by the area "B" in the figure. Then, the FSP would be paid for the actual decrease in consumption represented by the area C.

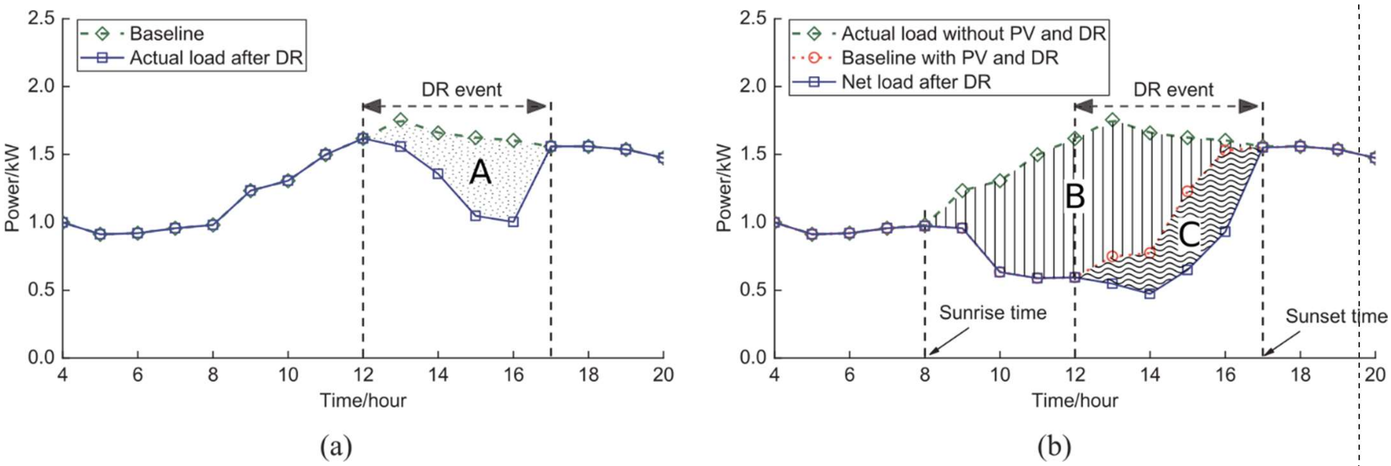


Figure 29: Example of baseline without DG (a) and with DG (b) behind the meter, [48]

Decoupling the distributed generation from the consumption when estimating the baseline is not straightforward. Li et. al [48], for instance, propose a machine learning algorithm to decouple the DG and the load patterns. Although this study advocates for the suitability of this method, it also highlights the challenges in terms of required data to have a robust model of the distributed generation, including the locational historical information of the output of the PVs. Besides, the machine learning algorithm can be seen as featuring *"low simplicity"*, if looked from the perspective of the baseline principles.

Historical data approach methods are expected to incur relevant losses of accuracy in the presence of behind-the-meter generation. Eventually, some methods could be tailored to try to compensate for the DG effect. The X of Y method could introduce an additive with respect to the weather, but, again, complexity is increased as location-specific data is required, and such additive may be also complex to calculate for small wind generators, for instance. The regression type of baseline methods could also include weather-related explanatory variables, but, again, their complexity would, then, increase. The meter before/meter after methods is the one that could be affected the least, not because it accounts for the effects of the DG behind the meter, but because of their simplicity. The comparable day method and the maximum baseload could also be appropriate, provided that enough past data is available to ensure that the conditions of activation day are considered. Otherwise, efficiency losses could occur for these two methods.

The metering generator output is the baseline method that aims to properly account for the DG, considering that an additional meter is installed. The most popular variant of this method, also referred as "zero baseline", would remunerate any production from the DG installation (therefore the baseline is zero), as this energy would have otherwise been withdrawn from the grid. This baseline method, despite accounting for the DG, does not provide incentives for additional consumption reduction. In the example of Figure 29, the consumer would be paid for area "B", despite and efforts to reduce consumption (area "C").

7.3.2. Aggregated baselines

Aggregation is expected to play an important role in enabling the participation of small FSPs in flexibility service provision, such as the congestion management markets in CoordiNet. Therefore, the effect of aggregation over the calculation of the baseline has to be considered as well. Considering the difference in the fitness of different baseline methods for different types of DER, it is also important to consider if the aggregated portfolio is composed of same-DER type FSPs, or if it is composed of multiple types of DER, in a Virtual Power Plant (VPP) configuration.

Therefore, the baseline for aggregated portfolios is discussed under two cases, namely when the aggregation consists of the same type of DER, and when different types of DER are aggregated together.

7.3.3. Aggregation of same type of DER

In the case of aggregation of same type of DER, the baseline method can be chosen according to the type of DER being aggregated. Some methods are straightforward and the aggregated form of the baseline is simply the summation of the individual ones, as for the “meter before/ meter after” or the maximum baseload. For other methods, such as the High X of Y, it is also possible for the baseline to be calculated in aggregated form directly.

1. **Individual baseline:** The performance is calculated at the individual site level, then summing those performances to calculate the performance of an entire FSP portfolio [40].
2. **Portfolio baseline:** The baselines are created by first using the aggregate meter data of all customers to generate a baseline for the aggregation and, then, using individual meter data to assign baselines to each customer [43]. It must be noted that the portfolio baselines are not an example of the statistical sampling approach, because such methodology is used where individual metering is not available.

The following example [43], clarifies the differences between the individual and the portfolio calculation. As shown in Figure 30, the program of the example uses a High 5 of 10 baseline and interval meter data from the last ten days prior to the event day is displayed. When the individual baseline is calculated, the selection of days to be considered is different for each consumer (shown in light blue), since the selection is based on the individual consumptions. However, if the baselines are calculated using the portfolio approach, out of the past 10 days, the highest five days of the portfolio are Days 1, 2, 4, 5, and 8 (shown in dark blue). Next, taking into account these days, the baseline is calculated for each participant (i.e. the baseline for each participant is calculated based on their individual loads in Days 1, 2, 4, 5 and 8). In this example, using the individual approach generates baselines that are higher than baselines generated using the portfolio method. Consequently, the aggregate load will be different in each calculation; if a portfolio baseline were used, the baseline for the aggregate load would be 378 kW, but if individual baselines were used, then the aggregate load baseline would be 437 kW. It is important to remark, that, in any case, the level of flexibility provided is measured at an individual prosumer level.

	Participant 1	Participant 2	Participant 3	Aggregate Load
Day 1	200	65	100	365
Day 2	200	65	80	345
Day 3	200	65	70	335
Day 4	200	130	80	410
Day 5	200	130	60	390
Day 6	0	130	80	210
Day 7	0	130	110	240
Day 8	150	130	100	380
Day 9	150	65	125	340
Day 10	150	65	100	315
High 5 of 10, Portfolio	190	104	84	378
High 5 of 10, Individual	200	130	107	437

Figure 30: Comparison of individual/portfolio baselines, [43]

As shown in the example above, calculating the baseline in an aggregated manner can lead to losses in accuracy and, possibly, in the efficacy, if baselines are consistently underestimated.

7.3.4. Aggregation of different types of DER

With regards to the aggregation of different types of DER under the same portfolio, it becomes apparent that one single baseline method can hardly be efficient for the portfolio as a whole. The exceptions to this are the static baselines "maximum baseload" and "meter before / meter after".

The maximum base load and the meter before/meter after are equally applicable to both individual and aggregated baselines. The former is a static baseline that sets a "cap" on the withdrawal of energy from the grid. This method can be applied to individual units or aggregated portfolios without major differences. The latter, given its simplicity, involves no difference if applied using and aggregated or an individual baseline. In fact, the aggregated form of this baseline method is simply the summation of all the individual metering data. Finally, with regards to the metering generator output method, assuming that an additional meter is installed to measure the generation of the behind-the-meter DG, aggregation could be possible for all those units.

Another possible baseline method that could be suitable for aggregation is the comparable day, also for multi-DER portfolios. However, this baseline method also has particularities that should be taken into account. It is an ex-post baseline chosen by the aggregator, provided the existence of a large set of past data in order to allow for the selection of similar day in terms of portfolio behaviour. This can be even more difficult in the case of a multi-DER portfolio, given the consumptions or production of the different units in uncorrelated.

If the other baseline methods are to be considered, a differentiated treatment of the different types of DER is needed. In this context, two approaches may be suggested, namely the grouping of baselines by either type of technology or by cluster.

The baseline methods used to an aggregated portfolio can be separated according to the type of technology, or type of DER being aggregated. In other words, specific baseline methods can be applied to the different DER types, according to what fits best each one of them. This approach should not be difficult to implement in the case where the different DER types are all different units, or delivery points, associated with individual meters. However, in the case of multiple DER types per unit, such as in a consumer with PV installation and EV charging stations, additional submetering data would be necessary. This would, on the one hand, increase the accuracy of the portfolio's baseline, but on the other decrease its simplicity.

As an alternative to using submetering data to decouple the different technologies, units could be grouped in clusters, and specific baseline methods could be applied to those according to clusters' characteristics. Cluster could be done by the types of DER combined. For example, residential consumers would be one cluster, consumers with PV another, and consumers with EV a third one. The advantage of this approach is that no additional data is required apart from the metering data already in place. The disadvantage is that accuracy may be impacted negatively.

7.3.5. Types of products

Congestion management products can be defined as capacity products or energy products. In CoordiNet, these two types are referred to as congestion management reserved and congestion management non-reserved, respectively (cf. Deliverable D1.3 [12]).

The congestion management reserved is a capacity-based product procured for congestion management services at a certain availability price, which is then activated when the service is needed by the relevant system operator. It is supposed to be more related to structural constraints and can be traded for longer periods of time.

The congestion management non-reserved is an energy-based product procured for congestion management services at an energy price (most likely to be procured closer to delivery given the fact that it is energy based).

For both types of product, verification is needed in order to certify that the procured service is being delivered by the FSP. In the cases of a non-reserved product, the baseline is the only tool required for this verification. As in the non-reserved products the service is also associated with an activation, the verification consists only in checking if the flexibility was or not provided. In a reserved product, however, the service consists of not only delivering flexibility upon activation, but potentially being available to deliver flexibility for an extended period of time (from hours to years). In this case, two different types of verification are necessary. Firstly, the **availability verification** is necessary to ensure the capability of delivering the flexibility, while the **delivery verification** is needed when the flexibility is activated. Reserved products require both types of verification, while non-reserved products require only the latter.

Availability verification can be done by stablishing a set of rules that can indicate to the TSO or DSO that the flexibility can be provided when needed. The objective for having such availability verification is also to avoid that FSPs offer more flexibility than they can provide. If no such verification is in place, the FSP could try to game the system, by offering capacities that they are unable to deliver. It could be the case that activation is so infrequent that, even paying possible penalties for non-delivery, the gaming FSP is still better off by considering the payments received for the availability. To avoid that, a set of rules, such as the ones below, could be designed. The rules would also depend on when the verification is carried out. Availability verification is needed both before the start of the flexibility contract and during its lifetime.

During the market clearing phase of the reserved service, a first availability verification should be done to ensure that the FSP will be able to provide the service. These conditions for participation in the service should be done before the beginning of the contract. During the lifetime of the contract, in a continuous manner, this verification should also be done, providing the TSO or DSO with confidence that the flexibility can still be delivered. Figure 31 exemplifies the lifetime of a reserved flexibility service contract and the different verifications needed during the contract.

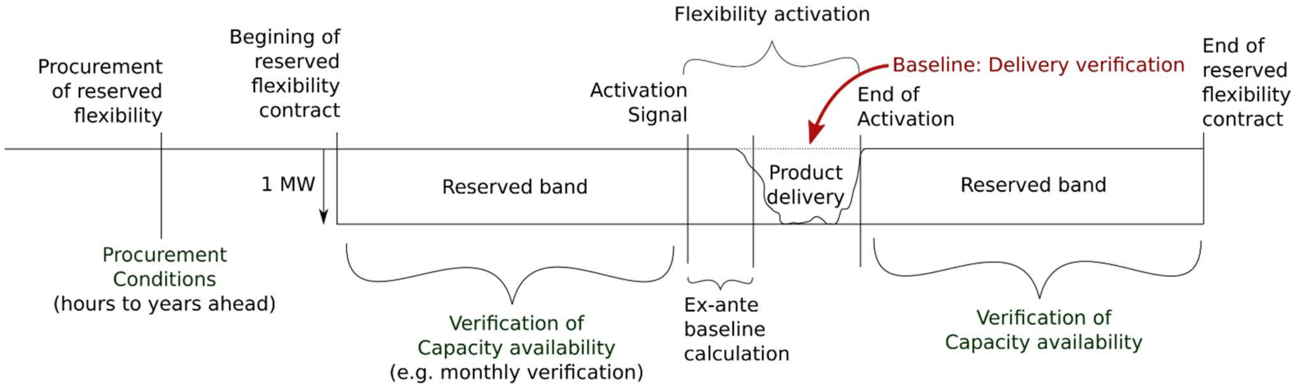


Figure 31: Example of a reserved flexibility service and the different types of verification required

Below, an example of a set of rules for availability verification is provided. These rules are inspired by the "Interruptibility contracts" for demand response in Spain. Within this demand response program, the Spanish TSO procures demand response capacity from industrial consumers in yearly auctions. Products are defined as a 5MW and a 40MW band of reserved capacity that can be activated upon the TSO's request, limited to a certain number or hours per year.

Procurement Conditions:

- Concentration of 50% of the monthly energy consumption in the peak hours.
- Average hourly consumption should not be lower than the capacity offered by the FSP on top of a base value to be informed by the FSP.
- Consumers with DG should calculate the requirements without considering the effects of DG.
- Have no pending penalties from previous reserved flexibility contracts of the same product.

Continuous availability verification (e.g. monthly verification):

- All procurement conditions above should be met during contract lifetime, plus
- notification of unavailability periods in advance, and with certain limits (e.g.<5% of contract life), and
- submission of consumption plan with accuracy of 75% considering non-activation hours.

With regards to the baseline methods considered in this analysis, both can be used for the delivery verification of both capacity and energy products. The difference lays in the fact that, in the case of a capacity product, the baseline is used only for verification, and not for settlement.

In both cases, the defining factor for the baseline method fitness is mostly related to the market timing, or when the service will be needed, when the activation will be made and when and how the baseline will be calculated and communicated. Only with regards to the minimum bid size, it should be noted that it should be large enough to be differentiated from the noise observed in real-time metering. On that matter, the accuracy of the baseline, too plays an important role.

7.3.6. Market timing

Congestion management markets can take place in different timeframes, from the long term (weeks ahead) to near real-time. As mentioned in the previous subsection, the market timing is usually associated with the type of product defined. Long-term congestion management markets tend to trade reserved congestion management products, while close-to-real-time markets tend to trade energy.

For the baseline definition, an important aspect from the implementation point of view is the timing of the activation process. As previously mentioned, capacity products only need a baseline to determine whether the service is being actually delivered, unless these products are defined as a capacity cap (which could be seen as a maximum base load baseline). Energy products do need a baseline for settlement, as well as for verification, but this baseline is only needed by the time of activation as well. Therefore, for both types, independent of the market timeframe (e.g. weeks-ahead, day-ahead, real-time), the timing of the activation process must be taken into account.

Certain baselines are simpler to compute than others. Baselines computed making use of any sort of ex-ante computation have to be considered within the time frame of activation process. For certain products, activation may take place on very short notice, and for short periods of time. This can be the case for capacity products, for instance, in which the system operator is entitled to change consumption or generation when the need arises. In such cases, the need to accommodate the data gathering and computation of the baseline in the activation process has to be considered. If the computation of baselines cannot be done within the activation process timeframe, baseline methods that require no previous computation can be considered, such as meter before/after, maximum base load, metering generator output and comparable day. However, the static baselines methods such as the meter before/after and the maximum baseline have the drawback of not being suitable for long activations, considering that they cannot be changed.

With regards to non-reserved products cleared with time in advance to the activation, one aspect to be considered is the gaming opportunities it may generate in certain baseline methods. If non-reserved market is cleared in the day-ahead, for instance, and the baseline calculation includes data after the gate closure time (GCT), the FSP may be able to game by trying to inflate the baseline (increasing consumption) during the hours between GCT and the baseline calculation/activation, as the FSP is already cleared in the congestion management market and knows with certainty that they will be activated. In this case, it is advisable to exclude those hours between the GCT and the activation for the baseline methods “High X of Y” (see Figure 32) and “Rolling average”. However, it is possible that the day of activation or the day before are relevant for the baseline calculation. In the High X of Y method, adjustments are usually calculated based on hours before delivery, and the rolling average weights the day before activation higher than the others in the historical series. Therefore, in cases in which those hours between GCT and activation still have to be taken into consideration, a set of rules should also be put in place, to ensure the right to the party procuring the service to verify the need and adequacy of that close to activation data. For instance, the Belgium TSO Elia defined that no adjustments are to be applied in their High X of Y baseline method for balancing services. Nevertheless, the FSP could request the calculation of adjustments. In this case, a three-month evaluation is carried out to compare results with and without adjustments. If adjustments are proven to be more efficient, they are introduced to the baseline calculation, but under certain conditions. If the baseline is increase by more than 15% with the adjustment, justifications are required and “Elia reserves the right to no longer apply an adjustment” [49].

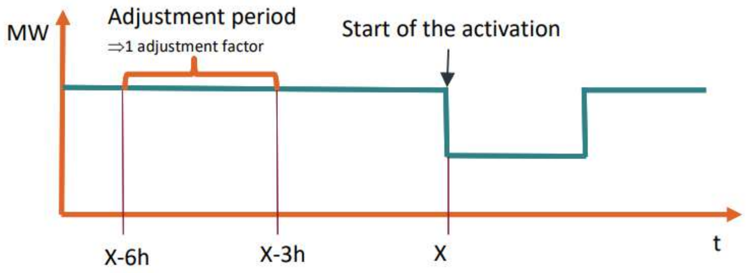


Figure 32: Adjustment period in a High X of Y baseline methodology. Hours between the day-ahead GCT and activation are used [49]

7.3.7. Market Models

In the congestion management markets of CoordiNet, it is possible that the baseline has to be calculated by one party, but applied to another one, considering the interactions between TSOs, DSOs and other stakeholders being tested. This, together with the timing of activation of the service, can also impact the choice of baseline method.

The fragmented and the local market models do not impose additional complexity in the baseline calculation. In these markets, the same system operator procures and activates the service from providers in their own network. As such, the same system operator is the responsible for the metering (necessary data for baseline calculation), the settlement, and the verification of service provision. In other market models, however, information exchange has to take place regarding the baseline computation and application and, therefore, implementation costs may rise.

Implementation costs and the associated level of investment in activities such as data transfer, data quality review, analysis, training, and IT systems requirements need to be considered for a simple baseline, a baseline of medium complexity, and a complex baseline methodology. Results consistent with earlier work indicate that the annual total cost to administer a complex baseline methodology is more than three times as much as that of a simple baseline methodology [45]. For market participants, the baseline operational feasibility is an important factor when determining the baseline method to be utilized. In the case that many of the baselines with an additive or multiplicative adjustment have very similar results, the administrative costs become a significant factor in determining which baseline method to choose.

In the multi-level market model, unused bids from the local market are sent to the central market. In this case, DSOs and TSOs will have to agree on how the data on the baseline computation and/or application will be sent as well. It is possible that, in the local market, small bids (<1MW) are allowed, but in the central market only >1MW bids can be used. Therefore, in addition to aggregating the bids, the DSO will also have to aggregate the baseline, and, for that matter, the discussion in subsection 7.3.2 applies.

7.4. An alternative to the calculation of the baseline

As mentioned in previous sections, the entity responsible for defining the baseline method and for its calculation should be the one procuring the flexibility service. However, one may argue that the baseline calculation can be a data-intensive process, also involving high costs for the party procuring the service. In this case, it is possible that the baseline calculation process and data handling can be shared with the party offering the service. In this case, it is clear that the integrity of the process is key, and additional mechanisms should be designed to avoid that the FSP manipulates the baseline calculation or simply do not look after the quality of the data and calculation.

The process of handing over the computation of the baseline to the FSP should require the implementation of verification methods and accountability criteria for accuracy and integrity. Additionally, this option should only be considered for selected FSPs, when it is supposed to make the process more efficient. Two possible cases where handing over the calculation of the baseline to the FSP may make senses are that of big individual FSPs and, eventually, that of the aggregators.

In the case of particularly big FSPs, such as industrial consumers (without individual schedules in wholesale markets), a consumption plan could be requested prior to the activation of the flexibility resources. This production plan would most probably be requested in the market clearing phase, when the delivery of the product is scheduled, as illustrated in Figure 33. However, without verification or accountability mechanisms, the FSP may probably have opportunities for gaming. An overestimated consumption plan could lead the FSP to receive the payment for activation without reducing any load.

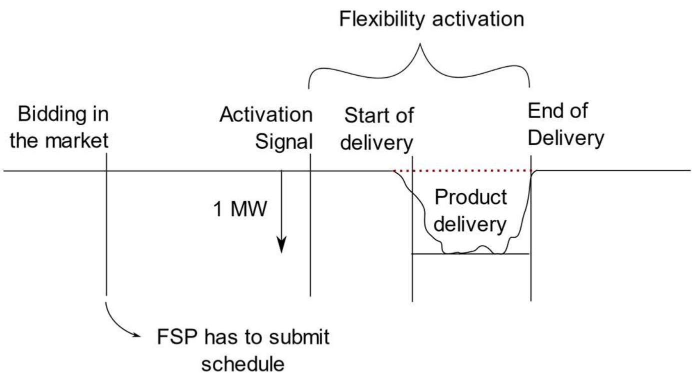


Figure 33: Schedule request as alternative for the baseline calculation

To mitigate this risk, additional mechanisms are necessary. As in the availability verification process for reserved flexibility products (e.g. capacity), a set of rules could be in place to ensure the quality and accuracy of the schedule provided. Examples of such rules could include:

- Schedule consumption within a certain range of historical values. Industrial consumers should have a stable consumption pattern, and sudden differences should be accompanied with a justification, in case they happen in a day of flexibility activation.
- In case of misleading baselines, after checked by the TSO/DSO, the exclusion of the FSP for future market participation.

As mentioned above, this schedule request alternative is only a viable solution for large FSPs, as these units have an important impact on the service as a whole and, therefore, it is reasonable for the DSO/TSO to verify the provision of flexibility on a case-by-case basis.

The second case in which the baseline could be provided by the FSP is the aggregation of a large number of small FSPs. In such cases, although the DSO would have the metering data required to calculate the baseline, this would also require an adaptation in systems and infrastructure, and, therefore, incurring additional costs. Besides, depending on the way the baseline is calculated, this may require the use of submetering data, as discussed in subsection 7.3.2. But the aggregator is already in possession of the submetering data. In this case, the aggregator would calculate and send the baseline value calculated to the party procuring the service.

7.5. Decision framework for baseline method selection

Considering the assessment above within the proposed methodology, this section tries to summarize this analysis and, finally, proposes a tool to help on the baseline method selection process considering the different characteristics of the product and the participants to which the baseline is applied to. This tool adopts the form of a decision tree, as shown in Figure 34.

The starting point is the verification of whether the FSP is already individually scheduled (i.e. the FSP has a demand and generation plan committed for other markets such as the day-ahead market). In this case no additional baseline would be required, as the schedule of the FSP would serve as a baseline.

The second consideration is if the FSP is aggregated or not. If the FSP is one individual unit, different baseline methods can be considered for the different types of DER. The specific baseline to be chosen may also depend on the product and unit characteristics. Additionally, the design option to implement should also depend on the market characteristics. For instance, if the market is for a non-reserved product (e.g. energy) with a GCT many hours ahead of the activation, historical data methods should exclude those hours between to GCT and the activation from the calculation to avoid gaming.

If the FSP is aggregated, a key aspect to consider is if the portfolio includes only the same type of DER, or different types (e.g. in a VPP concept). In the former, baseline methods can be chosen using the same proposal as for the individual units. From the perspective of the calculation, for methods such as the High X of Y, individual calculation (per delivery point) is recommended [44]. If the baseline is for a VPP type of aggregation, submetering could be used to calculate baselines per technology. Otherwise baseline for clusters could be used, offering greater simplicity but possible lower accuracy. Alternatively, the “comparable day” or the “maximum base load” are also viable for a multi-DER aggregation.

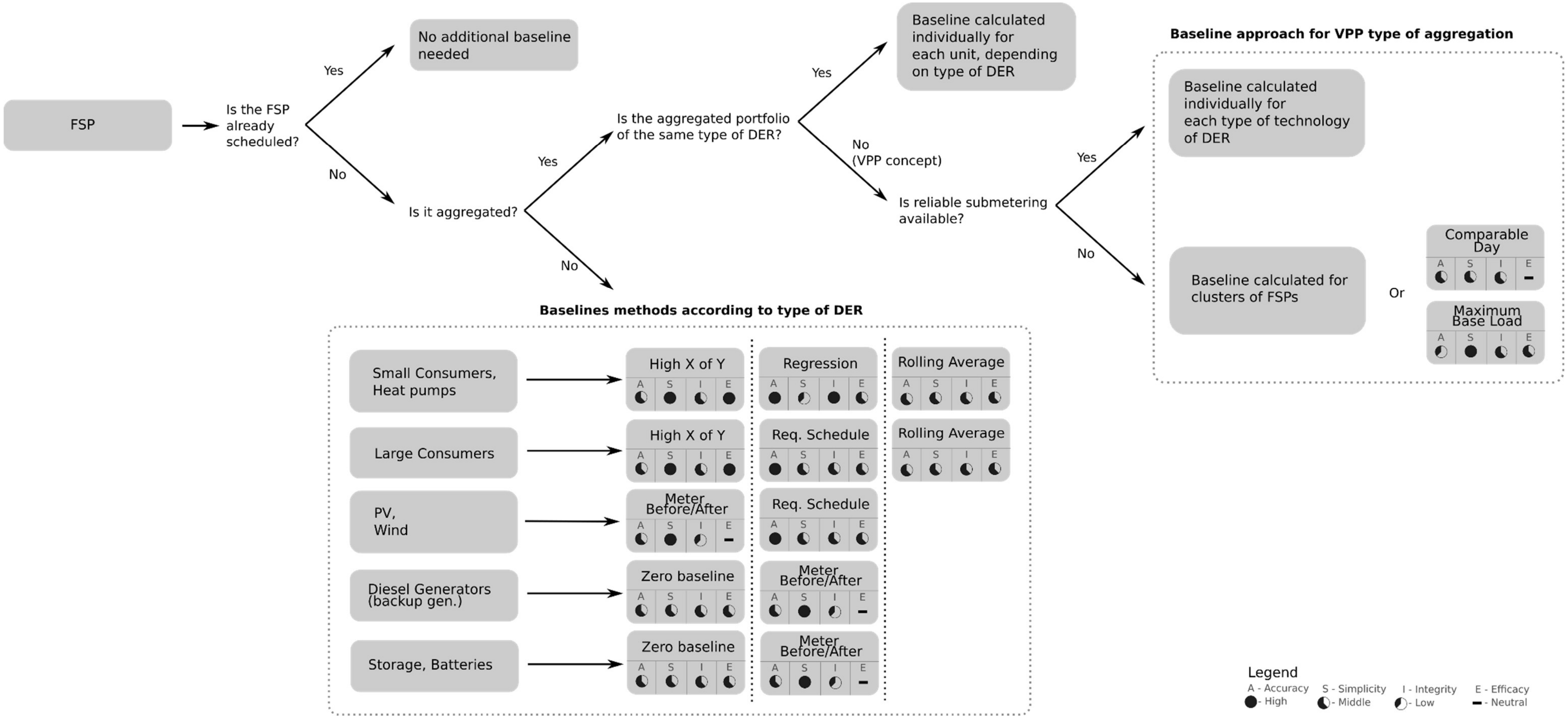


Figure 34: Baseline decision framework

7.6. Recommendations for the demonstrations

This section provides recommendations for each of the demonstrations according to the specific characteristics of the BUCs and FSPs involved. The recommendations provide the most suitable options for the demonstrations, highlighting their advantages and disadvantages with respect to the evaluation criteria previously defined.

7.6.1. Spain

As stated in section 5.1, congestion management in the Spanish demonstration campaign will be demonstrated in two different BUCs, ES-1a - Common congestion management and ES-1b - Local congestion management.

ES-1a - Common Congestion Management

The BUC ES-1a proposes a common market model for congestion management, and its main objective is to procure flexibility from the resources connected at both TSO and DSO level networks in a coordinated manner to solve transitory congestions that can occur in both networks. Table 32 summarizes the resources expected to participate in this BUC, which comprise wind farms, small hydro, photovoltaic stations, natural gas and biogas generation, cogeneration, and demand-side resources. These assets are located in Cadiz, Malaga, Albacete, Murcia, and Alicante. Among the resources considered in this BUC, not all require the calculation of a specific baseline, because the congestion market in Spain opens after the day-ahead market has closed and its clearing results are known. The results of the day-ahead energy market are going to be used as the baseline to determine the reference for the flexibility offered in the congestion market sessions. The latter applies as long as the resources are individually scheduled in the day-ahead market, regardless of whether they are aggregated or not.

For instance, all resources except to sFSP_MAL 2-5 would already be scheduled in the day-ahead market. Therefore, that scheduling serves as a baseline for those units, see the column “individually scheduled” in Table 32. For resources that are no scheduled individually, a baseline is required for the congestion management process. The recommendations and the calculation process of their baselines are addressed in the next paragraphs.

Table 32: Assets description participating in the common congestion management market of the Spanish demonstrator, [50]

DER name	Location	Type of DER	Capacity [MW]	Individually scheduled?	Aggregation	Notes
Wind CAD 1	Cadiz	Wind Farm	10.68	Yes	No	Connected to DS-20kV
Wind CAD 2	Cadiz	Wind Farm	32	Yes	No	Connected to DS-20kV
Wind CAD 3	Cadiz	Wind Farm	42	Yes	No	Connected to DS-20kV
Wind CAD 4	Cadiz	Wind Farm	6	Yes	No	Connected to DS-66kV
Solar CAD 1	Cadiz	Photovoltaic Station	12.3	Yes	No	Connected to DS-66kV
sFSP_MAL2 (Microgrid)	Malaga	PV	15	No	All resources integrated in the same Aggregator,	Connected to LV-0.4kV
		Batteries	72			
		V2G charger (prosumer)	TBC			
sFSP_MAL3	Malaga	Buildings (Museum 1-2, Building, Module 1-7)	1125	No		Connected to LV-0.4kV

sFSP_MAL4	Malaga	Smart Home PV Batteries V2H (prosumer)	31.2	No	submetering available.	Connected to LV-0.4kV
sFSP_MAL5	Malaga	PV and lighting	0.1	No		Connected to DS-20kV, Convention center.
COGEN_MAL 1	Malaga	Natural Gas Cogeneration	10	Yes	No	Connected to DS-20kV, 4 thermal groups
BIOGAS_MAL 1	Malaga	Biogas Generation	2.096	Yes	No	Connected to DS-20kV, 4 thermal groups
Wind ALB 20	Albacete	Wind Farm	48	Yes	Yes	132kV from SUB_ALB1 to SUB_ALB3
Wind ALB 21	Albacete	Wind Farm	24.42	Yes	Yes	Connected to SUB_ALB5
Hydro ALB 1	Albacete	Small Hydro	6.03	Yes	Yes	132kV from SUB_ALB1 to SUB_ALB3
Hydro ALB 2	Albacete	Small Hydro	9.79	Yes	Yes	132kV from SUB_ALB1 to SUB_ALB3
Hydro ALB 3	Albacete	Small Hydro	13.68	Yes	Yes	132kV from SUB_ALB1 to SUB_ALB3
Hydro ALB 4	Albacete	Small Hydro	4.8	Yes	Yes	66kV dep 132kV from SUB_ALB1 to SUB_ALB3
Hydro ALB 5	Albacete	Small Hydro	8	Yes	Yes	20kV dep 132kV from SUB_ALB1 to SUB_ALB3
Hydro ALB 6	Albacete	Small Hydro	8	Yes	Yes	Connected to DS-66kV
Hydro ALB 7	Albacete	Small Hydro	3.84	Yes	Yes	Connected to DS-66kV
Cogen ALB 1	Albacete	Cogeneration	24	Yes	No	132kV SUB_ALB7 to SUB_ALB4
Cogen MUR 1	Murcia	Cogeneration	90	Yes	No	132kV SUB_MUR1 to SUB_MUR2
Customer ALI 1	Alicante	Industrial Demand	22.1	Yes	No	Connected at 132kV line.

ES-1b - Local Congestion Management

The BUC ES-1b considers a local market model, and its principal objective is to procure flexibility from resources connected at the DSO LV networks to solve transitory congestions that can occur at the DSO LV networks. According to D3.1 [50], the resources expected to participate in this BUC are located in Malaga and Murcia, and they are composed of buildings, and microgrids including several types of flexibility resources, as shown in Table 33. All resources considered in this BUC require a baseline for the congestion management process, because they are not individually scheduled in the day-ahead market. Therefore, recommendations and the calculation process of their baselines will be addressed in the next subsubsection.

Table 33: Assets description participating in the local congestion management market of Spanish demonstrator, [50]

DER name	Location	Type of DER	Capacity [kW]	Individually scheduled?	Aggregation	Notes
sFSP_MAL1 (Microgrid)	Malaga	PV - lighting	1	No	All resources integrated in the same Aggregator,	Connected to LV-0.4kV
		PV - sunshade	9			
		Batteries GEL	38			
		Wind generator	1			
		Public lighting	6			
		V2G charger (prosumer)	TBC			
sFSP_MAL2 (Microgrid)	Malaga	PV	15	No		Connected to LV-0.4kV
		Batteries	72			

		V2G charger (prosumer)	TBC		submetering available.	
sFSP_MAL3	Malaga	Buildings (Museum 1-2, Building, Module 1-7)	1125	No		Connected to LV-0.4kV
sFSP_MAL4	Malaga	Smart Home PV Batteries V2H (prosumer)	31.2	No		Connected to LV-0.4kV
Line_MUR 3	Murcia	Buildings	779	No	No	Connected to MV
Line_MUR 4	Murcia	Buildings	88	No	No	Connected to LV

7.6.1.1. Baseline recommendations

ES-1a - Common Congestion Management

As indicated in Table 32 for ES-1a, the following resources are individually scheduled in the day-ahead market, Wind CAD 1-4, Solar CAD 1, COGEN_MAL 1, BIOGAS_MAL 1, Wind ALB 20-21, Hydro ALB 1-7, Cogen ALB 1, Cogen MUR 1, and Customer ALI 1. For all of them, no additional baseline is needed.

By contrast, the rest of the resources in Malaga (sFSP_MAL2, sFSP_MAL3, sFSP_MAL4, and sFSP_MAL5) are not previously individually scheduled. Then, a baseline should be calculated for them, considering the baseline evaluation framework described earlier in this chapter. These resources are integrated into one aggregator and submetering is available (see Table 32), and the aggregation considers different types of DERs. This suggests that the same baseline method could be calculated for each type of technology of DER. For example, for PV generation the meter before/meter after could be applied, as this is an available method for accurately estimating event response under real-time dispatch conditions. Comparable day and MBL methods are also feasible, according to the evaluation of Table 31. Similarly, for batteries, the zero baseline and meter before/meter after methods could be used. On the other hand, for the load flexibility resources (public lighting and buildings) historical data approach baselines are more suitable, and all these four baseline methods are possible. For instance, sFSP_MAL3 is a municipality building with different public offices, a museum and a start-up campus. Hence, a regression baseline can be considered and the regression model would include calendar variables (e.g., day of the week, holiday indicators, season) improving the accuracy of the baseline.

A summary of the baseline recommendations for the BUC ES-1a is presented in Table 34.

Table 34: Summary of possible baseline options for the BUC ES-1a Common Congestion Management – Spanish demonstrator

DER name	Type of DER	Location	Baseline strategy	Baseline method recommended
Wind CAD 1 -4	Wind Farms	Cadiz	**No additional baseline is needed**, because these resources are already individually scheduled in the day-ahead market.	
Solar CAD 1	Photovoltaic Station	Cadiz		
COGEN_MAL 1	Natural Gas Cogeneration	Malaga		
BIOGAS_MAL 1	Biogas Generation	Malaga		
Wind ALB 20 -21	Wind Farms	Albacete		
Hydro ALB 1 -7	Small Hydro	Albacete		
Cogen ALB 1	Cogeneration	Albacete		
Cogen MUR 1	Cogeneration	Murcia		
Customer ALI 1	Industrial Demand	Alicante		

sFSP_MAL2	PV	Malaga	Baseline calculated individually for each type of technology of DER, because submetering is available, and the aggregation considers different types of DERs.	Meter before /Meter after, Comparable day, Maximum base load.
	Batteries			Meter before /Meter after, Metering generator output.
	V2G charger (prosumer)			Regression, and other historical data approaches are feasible.
sFSP_MAL3	Building			Regression, High X of Y, and other historical data approaches are feasible.
sFSP_MAL4	Smart Home PV Batteries V2H (prosumer)			**V2H:** Regression, and other historical data approaches are feasible. **PV:** Meter before /Meter after, Comparable day, Maximum base load.
sFSP_MAL5	PV and lighting			**Lighting:** Regression, High X of Y, and other historical data approaches are feasible, for lighting. **PV:** Meter before /Meter after, Comparable day, Maximum base load.

ES-1b - Local Congestion Management

As stated in this subsubsection and before this paragraph, in this BUC all resources need a baseline. In the case of Malaga, because sFSP_MAL2, sFSP_MAL3, and sFSP_MAL4 participate in both businesses use cases ES-1a and ES-1b, the same recommendations as in Table 34 are feasible. Moreover, for the wind generator in sFSP_MAL1 the request of a production/consumption plan could be an option. For resources in Murcia, Line_MUR 3 and Line_MUR 4 are loads that are not aggregated and submetering is not available for them (see Table 33). Hence, the baseline would be calculated individually for each resource, and all historical data approaches are recommended. The best methods to choose would depend on the type of load considered and the timing of the activation process. For example, the comparable day method is simpler to implement on short notice/short duration than the High X of Y, regression, or rolling average methods.

A summary of the baseline recommendations for the BUC ES-1b is presented in Table 35.

Table 35: Summary of possible baseline options for the BUC ES-1b Local Congestion Management - Spanish demonstrator

DER name	Type of DER	Baseline strategy	Baseline method recommended
sFSP_MAL1	PV - lighting	Baseline calculated individually for each type of technology of DER, because submetering is available, and the aggregation considers different types of DERs.	**PV:** Meter before /Meter after, Comparable day, Maximum base load. **Lighting:** Regression, High X of Y, and other historical data approaches are feasible, for lighting.
	PV - sunshade		
	Batteries GEL		Meter before /Meter after, Metering generator output.
	Wind generator		Req. Scheduled
	Public lighting		Regression, High X of Y, and other historical data approaches are feasible, for lighting.
	V2G charger (prosumer)		Regression, and other historical data approaches are feasible.

sFSP_MAL2	PV		Meter before /Meter after, Comparable day, Maximum base load.
	Batteries		Meter before /Meter after, Metering generator output.
	V2G charger (prosumer)		Regression, and other historical data approaches are feasible.
sFSP_MAL3	Museum 1 Museum 2 Building Module 1-7		Regression, High X of Y, and other historical data approaches are feasible.
sFSP_MAL4	Smart Home PV Batteries V2H (prosumer)		**V2H:** Regression, and other historical data approaches are feasible. **PV:** Meter before /Meter after, Comparable day, Maximum base load.
Line_MUR 3	Buildings	Baseline calculated individually for each resource.	Regression, High X of Y, and other historical data approaches are feasible.
Line_MUR 4	Buildings		

7.6.1.2. Baseline calculation process

ES-1a - Common Congestion Management

Considering that the product being tested in this BUC is non-reserved congestion management, the baseline calculation will be needed for the delivery verification and settlement process. Consulting the BUC ES-1a diagram (Figure 35) in D3.1, it can be suggested that the baseline calculation for this BUC takes place once the common congestion management market clears (step 10.2), and when the FSPs receive the activation signal (step 15.2), if the baseline needs to be computed a priori.

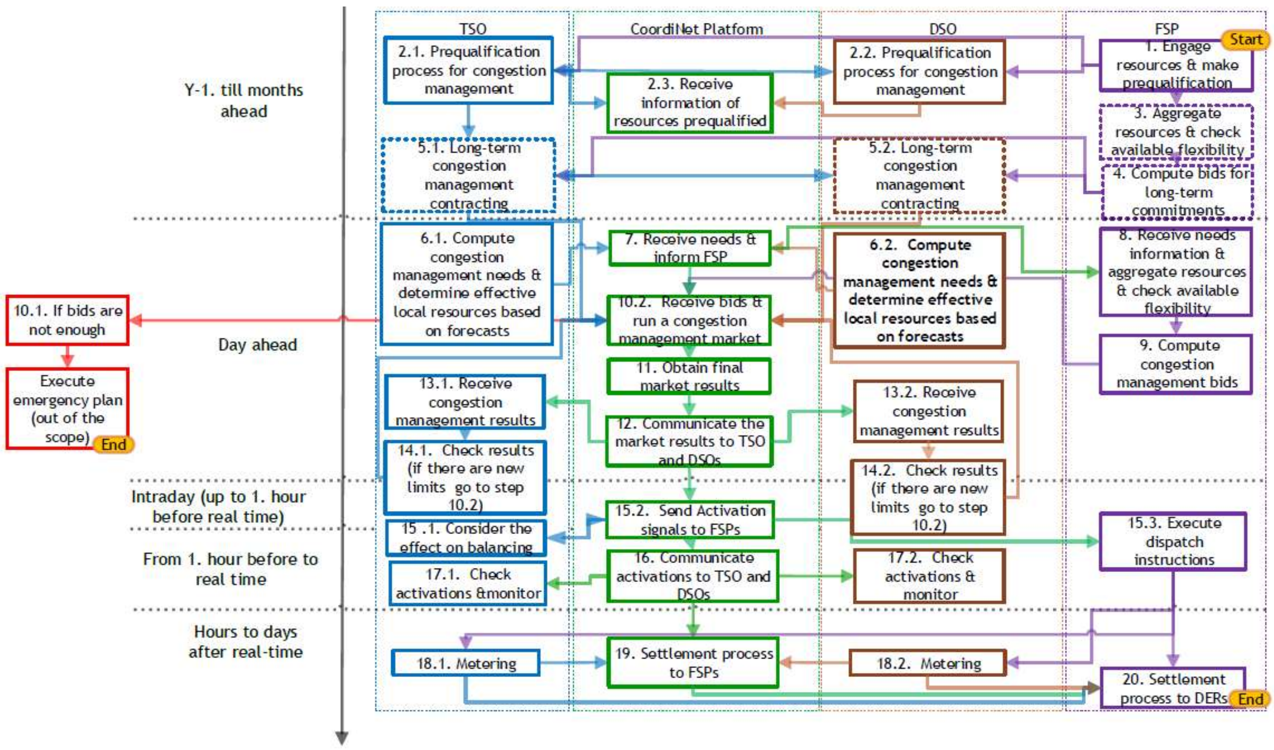


Figure 35: Timestep in which the baseline calculation would take place in BUC ES-1a, [50]

ES-1b – Local Congestion Management

Considering that the products being tested in this BUC are reserved and non-reserved congestion management, two types of verification (availability and delivery) processes will be performed for capacity products, and only the delivery verification is required for energy products. Therefore, the baseline calculation will be needed for the delivery verification of both products, and for the settlement process for non-reserved congestion management.

The BUC ES-1b diagram (Figure 36) in D3.1 suggests that the baseline calculation takes place in step 6 when the FSP computes the baseline and sends it to the DSO. This is in line with the alternative proposed in section 7.4, where the baseline is implemented by the party offering the service. Therefore, baseline methods with low-integrity performance should be avoided, and additional mechanisms should be designed to prevent that the FSP manipulates the baseline calculation. Another option could be to compute the baseline once the congestion management market clears (step 10.1), and when the FSPs receive the activation signal (step 14), if the baseline needs to be computed a priori.

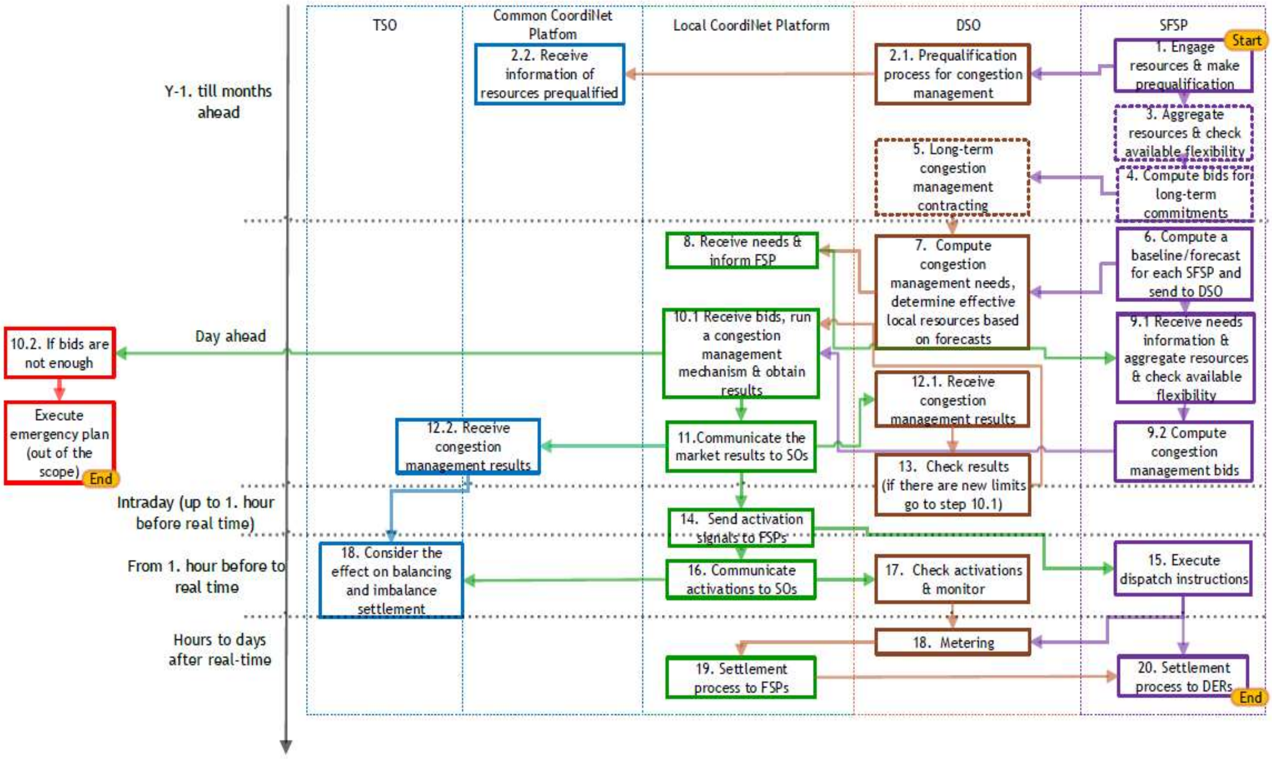


Figure 36: Timestep in which the baseline would take place in BUC ES-1b, [50]

7.6.2. Sweden

The Swedish demonstration on congestion management is organized on two different BUCs. The BUC SE-1a is a multi-level market model. On the first stage, a local and regional congestion management are run. Remaining bids are transferred to the TSO's balancing market (BUC SE-3). The BUC SE-1b, on the other hand, is a peer-to-peer market between generators buying flexibility and DER providing it. This market will take place in situations where there is congestion, in which a generator would be curtailed. To avoid that, they can buy extra flexibility, provide by other generation or demand, in the peer-to-peer market. More details on the characteristics of these two BUC are described in sections 6.3 and 6.2 for BUCs SE-1a and 1b, respectively.

The Swedish demonstration campaign has already carried out the demo run 1, at the time of writing this deliverable. For the demo run 2, several resources will be added, in addition to those that already participated in the first demo run. Table 36 below summarizes the resources according to their types.

Table 36: Summary of DER types in the Swedish demo run 2

FSP types participating in the demo run 2 in Sweden			Flexibility Volume (in MW)
Demand	Heat pumps	Residential (aggregated)	4
		Industrial	2
		District	97
	District Electric Boilers		29
	Buildings		<1
	Industry		19
	Refrigeration system - farm		1
Generation	Waste incineration (cogeneration)		10
	Gas turbine (cogeneration)		16
	Diesel generators		51
	Hydro Power		60
	Reserve Power Generation		88
Energy storage			6

At the consumption side, most of the flexibility volume provided is either from heat pumps or electric boilers, both highly weather-dependent. The exceptions are commercial buildings, one industrial consumer and a rural refrigeration system. On the generation side, diesel generators, hydro power plant and reserve power generation makes for most of the flexibility offered, followed by the cogeneration units of waste incineration and gas turbines.

7.6.2.1. Methodologies applied to CoordiNet context

Considering that demo run 1 already took place in Sweden, baseline methodologies were already needed and tested. In the first stage of the Swedish demonstration campaign (demo run 1), the following baseline methodologies were applied (the information collected and presented here is based on available information through D4.1 and D4.5 as well as through inputs by SE demo partner Per Aslund).

The first method, referred to as the “plan principle”, relies on consumption plans submitted by the FSPs to define their baselines. In this regard, when a FSP intends to send a bid to the CoordiNet flexibility market, it is required that the FSP also submits its production/consumption plan to the DSO no later than 10:30 day-ahead. This plan refers to the flexibility resources’ expected electricity production/consumption before any requested flexibility action is taken, and accounts for any intraday adjustments. As this method relies on schedules submitted by the FSPs, it is considered to be a baseline methodology that relies on a trust system, in which the operator trusts the validity of the plan provided by the FSP. In addition, this process is continuously monitored by the DSO, so that if the outcome regularly deviates from the declared plans, the DSO will disqualify these plans.

The second baseline methodology used is based on data collected during time periods before and after delivery. The collected data before activation is interpolated to generate the baseline. Hence, this method falls within the concept of the meter-before meter-after baseline method. The time periods over which measurements are collected depend on the length of the time period over which flexibility is delivered. For shorter deliveries (single hours), emphasis is placed on the measurements during the hour before and after delivery. For longer deliveries, the time span before and after is increased to better capture a representative picture of the load pattern before and after delivery.

In addition, during demo run 2 of the Swedish demonstration campaign, different baseline methodologies are also planned to be tested. These methodologies are being discussed at the time of writing this deliverable between the grid operators and FSPs. For instance, the Swedish demonstration campaign has also carried out a consultation with stakeholders in order to collect their views on the verification of different types of DER, as presented in Figure 37 below.

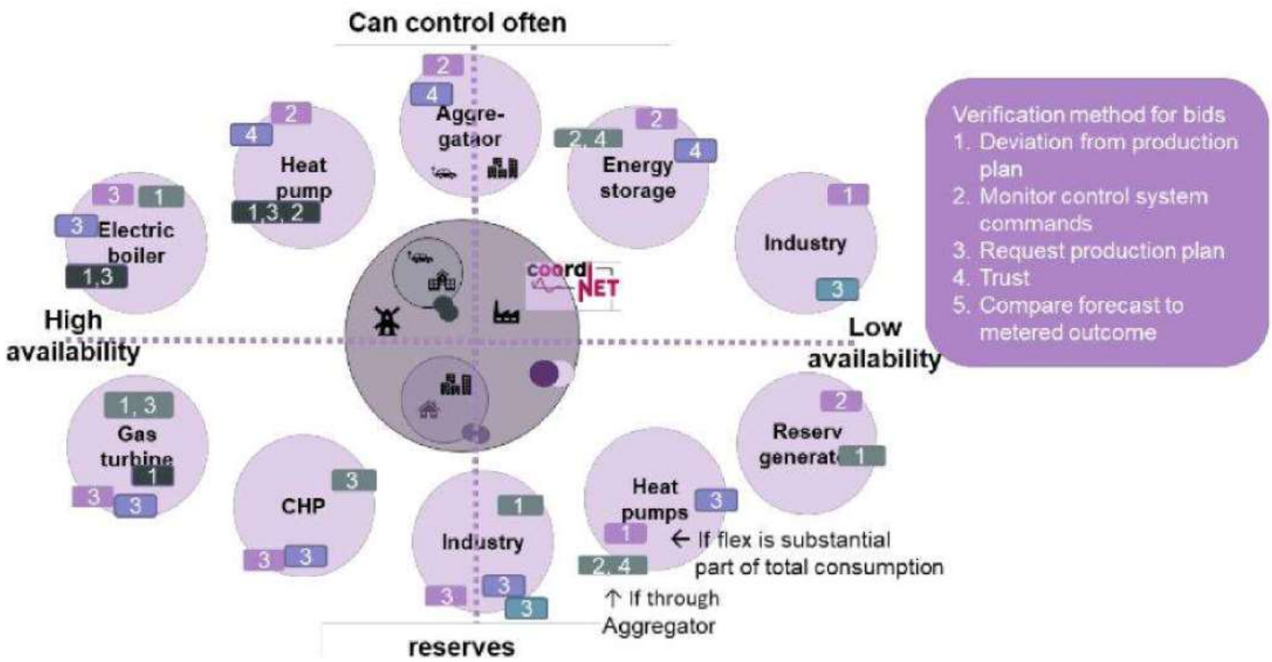


Figure 37: Proposals of verification methods for different types of flexibility resources, as collected from group work at the third public CoordiNet Forum, [22]

So far, several possible approaches have been discussed for the implementation in demo run 2. The first approach for computing the baseline relies on forecasting. In this regard, the forecasting approach is similar to a load forecast mechanism using machine learning. In other words, the forecaster would generate an estimate, using a machine learning mechanism, of what would the load profile of the FSP be during a certain time period if no flexibility were activated, and would then use that estimate as the baseline. Hence, this method falls within the scope of statistical sampling methods for baseline computation.

The second approach is referred to as the “similar day approach”, which uses representative time periods and days to establish the baseline. In this regard, the value of each hour (1-24) in a certain type of day (e.g. weekday or weekend/holyday) is based on the average of the last 3-5 values for the same category of day and hour. The average of these data points creates a “forecast” of the next day and is used as baseline. Hence, this method falls within the scope of “averaging baseline methods” as part of the “historical data” approach for baseline methodologies. In fact, this method mainly coincides with the last X of Y and last Y days baseline methodologies.

A third method considered is referred to as the “aggregator plans” and is similar to the “plan principle” used in the first run of the demonstration campaign, but it is extended to aggregators. This method, hence, also relies on a trust system in addition to continuous monitoring to observe whether the aggregator’s outcomes frequently deviate from the submitted plans, in which case a disqualification is applied.

The fourth method that is planned to be used is solely relevant for back-up generators and is referred to as the “zero plan”. In this regard, in the case of back-up generation, it is assumed that no generation would be provided if not acquired from the flexibility portal. Thus, the baseline is considered to be equal to zero.

In general, these different methods (and/or combinations thereof) are tested and evaluated in order to find a verification method that is trusted by the DSO and is understandable and accepted by the FSPs. The selection of method depends mainly on the type of facility/flexibility asset used. It is often preferable to use actual measurements, when such measurements are available at the required granularity level (i.e. capturing granular temporal changes as well as consumption levels for the different connected flexibility assets). In fact, if measurements cannot be obtained for a suitable location, it may be unclear whether the flexibility has been delivered in the event of an activation. Regarding the “plan principle”, a main driver for using this method is to possibly accommodate substantial fluctuations in the normal consumption that only the FSP is able to foresee.

7.6.2.2. Baseline recommendations

Considering the types of FSP participating in the congestion management market in Sweden[17] and the analysis of baseline methods developed in this chapter, the following baseline approaches could be considered for the Swedish demonstration.

Firstly, most of load FSPs are linked to heating, either in small distributed units (e.g. residential heat pumps) or large district heating facilities. Nevertheless, the consumption pattern of these units is expected to be highly correlated to weather conditions. Moreover, no DER combinations are expected. The household loads include only the effect of the heat pumps, and aggregation is, in principle, limited to the heat pumps only as well. Therefore, the selection and computation of the baseline could be simpler, as the effect of distributed generation (e.g. PV) or batteries are not coupled with the consumer’s flexibility.

Considering the expected correlation with weather variables and the absence of combination of DER types, baselines methods based on historical data could be suitable for the load FSPs in Sweden. More specifically, regression models could be suitable, as these can properly account for the correlation between weather and consumption, increasing the accuracy of the baseline. The methodology High X of Y could also be used for this type of DER, as well as the rolling average method. The drawback of these methods is the possibility of underestimating the baseline during the beginning of the winter, while overestimating it at the end. As these methods use short-term past data, in a constant increase of load scenario (beginning of winter), the baseline could be underestimated. To mitigate this risk, options are available for both methods.

For the High X of Y method, an adjustment can be considered. This adjustment can be calculated either by comparing the level of consumption in the hours before the activation with the calculated baseline, or by estimating an adjustment factor based on the temperature of the day. The latter can, besides, avoid gaming by the agents. If the adjustment is calculated based on the load in the hours before activation, gaming could occur if the clearing of the congestion management takes place before the hours used to calculate the adjustment. Knowing about an upcoming activation and the possibility of adjustment, the FSP could try to increase consumption during the adjustment hours to inflate the baseline. However, if the adjustment is

[17] Here the baseline is only considered for the BUC SE-1a, namely the congestion management market operated by the DSOs in order to prevent subscription (e.g. contracted capacity between network operators) violations.

calculated based on the temperature, the FSP would have no influence over the adjustment parameter. To compute this weather adjustment factor, a regression model could be used, as shown in [45].

For the rolling average method, one solution would be to assign a larger weight to the day or days closer to the activation day, in order to better capture the load conditions for a given weather.

For generation units, as well as for the industrial facility, the request of a production/consumption plan could be a feasible option. In fact, it is possible that most of these units are already individually scheduled in the wholesale market, and, therefore, the schedule is already available. However, if this is not the case, the schedule can be requested for these units, together with a set of verification mechanisms to ensure the accuracy and integrity of the provided schedule. Historical data approach methods, such as High X of Y and rolling average, could also be used for cogeneration and for industrial load. For diesel generators, hydro power plants and the overall reserve generation, these last methods may not be appropriate, considering that their output is volatile and not necessarily linked to peaks in the system. Additionally, if generators such as hydro power plants are already individually scheduled, no necessary baseline method is necessary as argued in section 7.3.

Finally, energy storage is also going to participate in the demonstration. As discussed in subsection 7.3.1, the meter before / meter after method could be used for this type of resource, provided that it is floored according to the direction of the flexibility being provided. In other words, for upwards flexibility, the battery will be at the discharging state. Therefore, the baseline will be the metered output of the battery, limited to zero, meaning that if the battery is at charging state before the activation, the charging power will not be considered for the effect of the baseline calculation. The reasoning for this approach is to preserve the integrity and efficacy of the baseline. If such limits are not in place, the battery could easily be set to charge during the baseline calculation and deliver the product (discharge) during activation hours. In this manner, the battery would be incentivized to charge just before the activation (possibly during already congested hours) to deliver the energy right after that. In terms of efficacy, it seems that this incentive is contrary to the objectives of the congestion management service. Also, by doing that, the battery is incentivized to try to inflate the baseline: discharge at t-2, charge at t-1 (at meter before, during the baseline calculation) and discharge again at t (product activation).

Table 37: Summary of possible baseline options for BUC SE-1a

<table>
<tr><th colspan="3">FSP types participating in the demo run 2 in Sweden</th><th colspan="3">Possible baseline methods</th></tr>
<tr><td rowspan="7">Demand</td><td rowspan="3">Heat pumps</td><td>Residential (aggregated)</td><td rowspan="4">Regression</td><td rowspan="4">Historic average: High X of Y with temperature adjustment</td><td rowspan="4">Historic average: Rolling Average</td></tr>
<tr><td>Industrial</td></tr>
<tr><td>District</td></tr>
<tr><td colspan="2">Buildings</td></tr>
<tr><td colspan="2">District Electric Boilers</td><td rowspan="2">Request schedule</td><td rowspan="2">Historic average: High X of Y</td><td rowspan="2"></td></tr>
<tr><td colspan="2">Industry</td></tr>
<tr><td colspan="2">Refrigeration system - farm</td><td>Regression</td><td>Historic average: High X of Y</td><td>Historic average: Rolling average</td></tr>
<tr><td rowspan="2">Generation</td><td>Waste incineration</td><td rowspan="2">Cogeneration</td><td rowspan="2">Request schedule</td><td rowspan="2">Historic average: High X of Y with temperature adjustment</td><td></td></tr>
<tr><td>Gas turbine</td><td></td></tr>
</table>

	Diesel generators	Request schedule		
	Hydro Power			
	Reserve Power Generation			
Energy storage		Meter before / meter after caped/floored		

7.6.2.3. Baseline calculation process

In case of the baseline methods high X of Y, rolling average, and regression, the calculation of the baseline should take place before the activation process, from a few hours to minutes ahead delivery. The request of schedule, however, should take place before market clearing, to avoid the risk of gaming. Adjustments on the submitted schedule should be allowed to increase accuracy (e.g. communication of unforeseen corrective maintenance), but they should be verifiable under certain rules (e.g. request of justification, limits up and down to the adjustment). Finally, the meter before / meter after should take place minutes before delivery. Figure 38 shows the placement of each baseline method in the market sessions timeline.

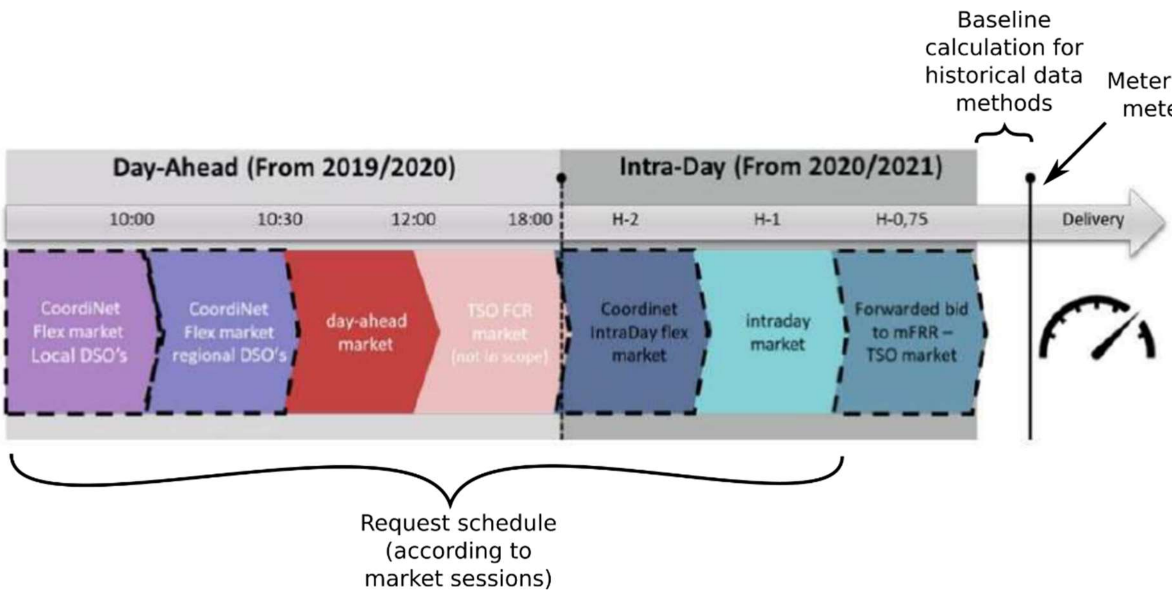


Figure 38: Baseline calculation timesteps, [22].

It is worth noticing that the baseline determination and the forecast are different processes that can take place in different timesteps of the congestion management process. The DSO needs to forecast the demand and consumption before the market takes places to evaluate the need for congestion management actions, which could take place several hours ahead delivery, before the markets are called and clear. The baseline, however, should estimate what would have been the consumption or production of an FSP if activation did not occur, based on the principles of accuracy, simplicity, integrity and efficacy. Most baseline methods will make use of close-to-real-time data to try to improve the accuracy of the baseline. The averaging methods (High X of Y and rolling average) may include adjustments to account for consumption or other factors such as the weather in the hours before delivery. Also, regression models will make use of weather data and other parameters collected close to real-time.

The baseline calculation and the forecasting also differ in the level of aggregation for which they are calculated. The forecast can be calculated by substation or other form of aggregation, while the baseline must be calculated for each FSP. Another difference between the baseline and the forecasting processes is that, for the latter, simplicity may not be a concern. The DSO may use advanced methods (e.g. machine learning algorithms) to best estimate the flexibility needs. Nevertheless, the baseline should also aim at being easy to communicate to FSPs, in such a way that market transparency is ensured.

7.6.3. Greece

The congestion management demonstration in Greece will take place in the island of Kefalonia and will be demonstrated in two different BUCs. The BUC GR-2a considers a multi-level market model, in which the TSO can access the flexibility connected at the distribution grid, as long as no constraints are created in the latter. The BUC GR-2b is a fragmented market model, in which the TSO cannot access the distributed resources.

According to D5.1 [51], the resources expected to participate in the congestion management demonstration are composed of wind farms, photovoltaic stations, small diesel generators and buildings, as shown in Table 38.

Table 38: Assets Description for Kefalonia

Type	Capacity [MW]	Monitored	Controllable	Notes
Wind Farm	39	✔	-	Connected to TS (Myrtos Substation)
Wind Farm	25.1	✔	-	Connected to DS
Photovoltaic Stations	3.743	✔	-	Connected to DS
Small Diesel Gensets	2	✔	✔	Gensets will be added after the successful tests
Buildings	TBD (probably 10 buildings)	✔	-	Part of engagement plan
Heat pumps	TBD			The heat pumps were not in the deliverable D5.1 [51], but they are expected to participate in the demonstrator according to partners.

From the resources considered in the demonstration campaign, not all require the calculation of a specific baseline. For instance, the two wind farms considered should already be scheduled in the wholesale markets, and, therefore, that scheduling serves as a baseline for those units. With respect to the PV units, these units will be only monitored to verify the need for congestion management, and not to provide the service. Therefore, no baseline is needed for these units either. The small diesel generators, the heat pumps, and the commercial buildings (hotel and office) are most probably not scheduled individually and, therefore, require a baseline for the congestion management process.

According to the planning of the demonstration campaign, an aggregator's tool will also be used. The aggregation carried out in the demonstration campaign will be done for the same type of DER only, both for the buildings and the heat pumps.

7.6.3.1. Baseline recommendations

Both congestion management BUCs will make use of the same resources. Therefore, the recommendations here provided can be given per type of DER unit.

For the small diesel generators, historical data approach methods are not suitable, as these units are dispatchable. Figure 39 shows that, for DG, the three simplest methods are more suitable, namely maximum base load, meter before/meter after, and metering generator output. Considering that these DG units are being treated independently, if connected to a load, the "zero baseline" could be a suitable method. This also takes into account the fact that these units are already monitored individually, as shown in Table 38. This baseline could be conflicting though if the diesel generators are used for multiple purposes other than the provision of the congestion management service (these units are also employed for backup purposes). In this case, meter before/meter after could also be used.

For the load flexibility providers, historical approach baselines could be more suitable. According to deliverable D5.1 [51], commercial and public buildings are being considered for the demonstrations. In this case, all four baseline methods are possible. Depending on the type of load, though, the rolling average method could be less accurate, if the building has a seasonal consumption pattern (e.g. hotel).

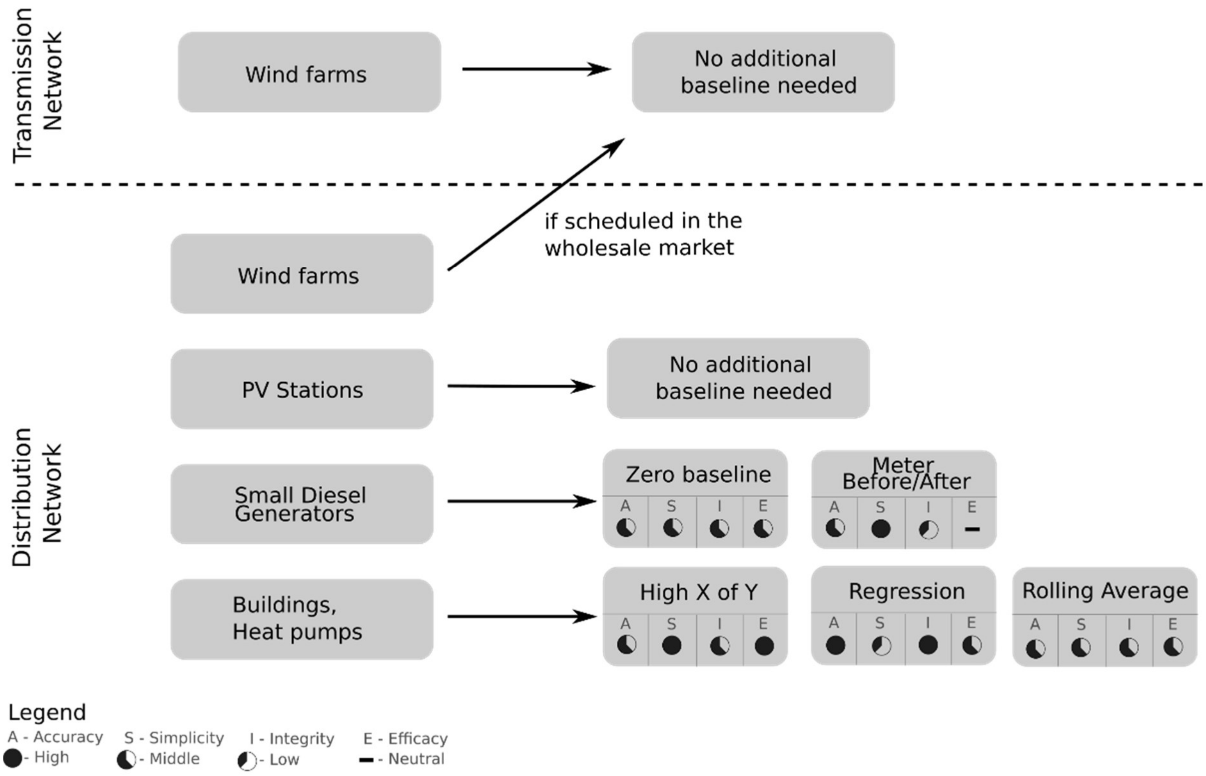


Figure 39: Summary of possible baseline options for the Greek demonstration

7.6.3.2. Baseline calculation process

Considering that the product being tested in the demonstration campaign is capacity, the baseline calculation will only be needed for the verification process and can, therefore, be calculated only in case of resource activation and close to the real-time.

In the case of the BUC GR-2b (fragmented model), the baseline calculation only takes place within the DSO local market. For the TSO, units providing flexibility for congestion management should be already scheduled in the wholesale market and, therefore, no additional baseline calculation is needed. For the DSO local market, the baseline calculation should take place only when units are activated close to real-time. Consulting the BUC diagrams in D1.5 [52], it can be suggested that the baseline calculation takes place when the DSO local market is cleared (see Figure 40), as this is the moment in which the FSPs receive the activation signal, in case the baseline requires prior calculation.

Figure 40: Timestep in which the baseline would take place in BUCs GR-1a and GR-1b. Adapted from D1.5 [52]

With regards to the multi-level market, in case the monitoring of service delivery is still carried out only by the DSO, possibly no transfer of the baseline information from the DSO to the TSO is needed. The baseline calculation would take place close to the real-time, as in the fragmented model, and the baseline would be equally calculated for both the FSPs providing service to the TSO and to the DSO. This information is then transferred to the market platform.

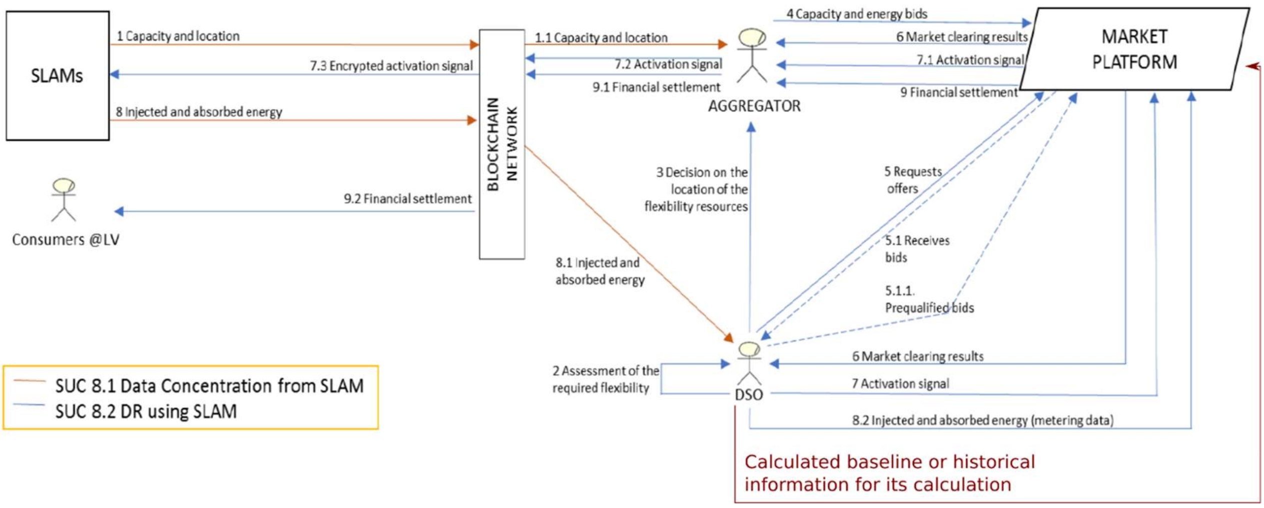


Figure 41: Suggested addition to the Primary Use Case 8 in the Greek demonstration. Adapted from D5.1 [51]

8. Market clearing functionalities, tools and requirements

The scope of this chapter is to list the identified market tools and their associated functionalities and requirements that are required to address the objective of the BUCs regarding market management. It is noted that since demonstration activities in Spain and Greece are at an early stage, the identification of tool functionalities and requirements has been carried out based on assumptions and the insights from the demonstrations' progress. Therefore, new functionalities or requirements might need to be identified in WP3-WP5, while some of the already identified ones might be withdrawn.

As summary, the steps followed to identify the tools, functionalities and requirements required to achieve the objectives of each demonstration are:

1. Identification of the demonstrators' needs based on the defined BUCs.
2. Identification of the required functionalities to address the needs.
3. Identification of the tools carrying out the identified functionalities.
4. Identification of the tool requirements to carry out the functionalities successfully.

A detailed explanation of the followed methodology is included in D2.2 [53]. For a better understanding of the work performed in this deliverable, the definitions of tool, functionality and requirement are provided below:

- A **tool** is defined as a system or a computer software used to perform an operation.
- A **functionality** is defined as a core function of a tool or a set of tools which should be performed for the tool(s) to meet the needs of the users. In other words, a functionality defines the objective of the tool(s).
- A **requirement** is defined as a criterion or a set of criteria which should be met in order for the tool to deliver the desired outcome. A requirement describes the tool behaviour, the simplifying assumptions which have been considered, data management procedures, the communication with other tools, etc. In other words, the requirements are the means by which a tool achieves its objective(s).

Following sections show the results of the analysis performed for the Spanish, Sweden and Greek demonstrators. It is noted that a similar tool can be necessary for more than one demonstration campaign, however, specific details might be different. Therefore, for each demonstrator, specific tools have been identified.

8.1. Spanish demonstrator

The market tools identified in the Spanish demonstrator are detailed in Table 39, while their related functionalities and their requirements are specified in Table 40 and Table 41 - Table 43 respectively.

Table 39: Identified tools of the Spanish demonstration campaign

ID	Tool	Brief description
m1	DSO market operation tool	It allows the operation, clearing and settlement of the local markets operated by the DSO
m2	TSO market operation tool	This tool is necessary for the central model approach in which the TSO is the single buyer on the market
m3	Common market operation tool	Tool developed for the common market approach in which a combination of local and central needs is

		considered and both DSO and TSO have access to the flexibility

For each functionality, the BUCs related to such functionality are specified, as well as the tools in which the functionality is considered.

Table 40: Identified functionalities of the Spanish demonstration campaign

ID	Functionality	Brief description	BUC(s)	Related tools (s)
1	Prequalification	Market operator receives information of prequalified resources	ES-1a, ES-1b, ES-2, ES-3, ES-4	m1, m2, m3
2	Flexibility bid filtering according to market model, prequalification and bid format	The market platform validates whether the bids sent by FSPs can be used to solve SOs needs according to prequalification process, market model considered and defined bid format. It also checks for temporary limits on balancing bids	ES-1a, ES-1b, ES-2, ES-3, ES-4	m1, m2, m3
3	Data exchange with other tools and actors	Market platform needs be able to exchange data with other tools, systems or actors, such as aggregator platform, DSO/TSO systems, FSPs, etc	ES-1a, ES-1b, ES-2, ES-3, ES-4	m1, m2, m3
4	Data exchange between the market platform tools	The individual tools that make up the market platform (e.g. DSO market operation, TSO market operation, common market operation tools) need be able to exchange data with each other	ES-1a, ES-1b, ES-2, ES-3, ES-4	m1, m2, m3
5	Market clearing for balancing	Market Operator clears the market considering the received bids (active or reactive)	ES-2	m2
6	Market clearing for voltage control	Market Operator clears the market considering the received bids (active or reactive)	ES-3	m3
7	Market clearing for congestion management	Market Operator clears the market considering the received bids (active or reactive)	ES-1a, ES-1b	m1, m3
8	Market clearing for controlled islanding	Market Operator clears the market considering the received bids (active or reactive)	ES-4	m1
9	Settlement process	Market operator settles process to FSPs	ES-1a, ES-1b, ES-2, ES-3, ES-4	m1, m2, m3

Next tables, from Table 41 to Table 43, show the requirements related to each of the identified tools. In addition to the description of the requirement and the BUCs related to such requirement, the priority of the requirements is indicated. This priority emphasises the importance of successfully implementing the requirement. A numerical scale is used, from 1 (unimportant) to 5 (critical).

Table 41: Requirements of the “DSO market operation tool” of the Spanish demonstration campaign

ID	Description	Type	Priority	BUC
1	The tool MUST collect and store the bids from the FSPs (D-A & I-D)	Functional & data	5	ES-1b, ES-4
2	The tool MUST collect and store the needs from the DSO (D-A & I-D)	Functional & data	5	ES-1b, ES-4

3	The tool MUST collect and store the network constraints from the DSO (D-A & I-D)	Functional & data	5	ES-1b, ES-4
4	The tool MUST clear the market in accordance with the market design specifications (D-A & I-D)	Functional & data	5	ES-1b, ES-4
5	The tool MUST store all the input and clearing results	Functional & data	5	ES-1b, ES-4
6	The tool MUST send the DSO needs for the D-A to the FSP	Functional & data	5	ES-1b, ES-4
7	The tool MUST communicate the complete D-A & I-D clearing results to the DSO	Functional & data	5	ES-1b, ES-4
8	The tool MUST communicate the FSP bid clearing results (D-A & I-D) to the FSPs	Functional & data	5	ES-1b, ES-4
9	The tool MUST communicate the FSPs bids clearing results (D-A & I-D) to the TSO market operation tool	Functional & data	5	ES-1b, ES-4
10	The tool SHOULD collect the baseline from the FSPs	Functional & data	4	ES-1b (Málaga)
11	The tool SHOULD run based on a predefined schedule (e.g. every day at 14:30 for the D-A market).	Functional & data	4	ES-1b, ES-4
12	The tool SHOULD be able to compute the settlement implication from the clearing results	Settlement	4	ES-1b, ES-4
13	The tool SHOULD identify the bids that can participate in the market (bid prequalification, etc.)	Functional & data	4	ES-1b, ES-4
14	The tool MUST collect and store the prequalified resources (whenever required)	Functional & data	5	ES-1b, ES-4

Table 42: Requirements of the “TSO market operation tool” of the Spanish demonstration campaign

ID	Description	Type	Priority	BUC
1	The tool MUST collect and store the bids from the FSPs	Functional & data	5	ES-2
2	The tool MUST collect and store the limits established by the DSO	Functional & data	5	ES-2
3	The tool MUST collect and store the needs from the TSO	Functional & data	5	ES-2
4	The tool MUST clear the market in accordance with the market design specifications	Functional & data	5	ES-2
5	The tool MUST store all the clearing results	Functional & data	5	ES-2
6	The tool MUST communicate the DSO need clearing results to the DSO	Functional & data	5	ES-2
7	The tool MUST communicate the TSO need clearing results to the TSO	Functional & data	5	ES-2
8	The tool MUST communicate the FSP bids clearing results to the FSPs	Functional & data	5	ES-2
9	The tool SHOULD run based on a predefined schedule (e.g. Every day at 14:30 for the D-A market).	Functional & data	4	ES-2
10	The tool SHOULD be able to compute the settlement implication from the clearing results	Settlement	4	ES-2
11	The tool SHOULD identify the bids that can participate in the market (bid prequalification, etc.)	Functional & data	4	ES-2
12	The tool MUST collect and store the prequalified resources (whenever required)	Functional & data	5	ES-2

Table 43: Requirements of the “Common market operation tool” of the Spanish demonstration campaign

ID	Description	Type	Priority	BUC
1	The tool MUST collect and store the bids from the FSPs	Functional & data	5	ES-1a, ES-3

2	The tool MUST collect and store the needs from the DSO	Functional & data	5	ES-1a, ES-3
3	The tool MUST collect and store the needs from the TSO	Functional & data	5	ES-1a, ES-3
4	The tool MUST clear the market in accordance with the market design specifications	Functional & data	5	ES-1a, ES-3
5	The tool MUST store all the clearing results	Functional & data	5	ES-1a, ES-3
6	The tool MUST communicate the DSO need clearing results to the DSO	Functional & data	5	ES-1a, ES-3
7	The tool MUST communicate the TSO need clearing results to the TSO	Functional & data	5	ES-1a, ES-3
8	The tool MUST communicate the FSP bids clearing results to the FSPs	Functional & data	5	ES-1a, ES-3
9	The tool MUST communicate needs from DSO and TSO to FSPs (when and where the congestion management market is opened)	Functional & data	5	ES-1a, ES-3
10	The tool SHOULD identify the bids that can participate in the market (bid prequalification, etc.)	Functional & data	4	ES-1a, ES-3
11	The tool SHOULD run based on a predefined schedule (e.g. Every day at 14:30 for the D-A market).	Functional & data	4	ES-1a, ES-3
12	The tool SHOULD be able to compute the settlement implication from the clearing results	Settlement	4	ES-1a, ES-3
13	The tool MUST collect and store the prequalified resources (whenever required)	Functional & data	5	ES-1a, ES-3

8.2. Swedish demonstrator

The market tools identified in the Swedish demonstrator are detailed in Table 44, while their related functionalities and their requirements are specified in Table 45 and Table 46 - Table 48 respectively.

Table 44: Identified tools of the Swedish demonstration campaign

ID	Tool	Brief description
m1	DSO market operation tool	It allows the operation, clearing and settlement of the local markets operated by the DSO. Once its needs are covered, the DSO transfers flexibility bids to the central market at TSO level
m2	TSO market operation tool	This tool is necessary for the acquisition of flexibility by the TSO, who has access to flexibility provided by DER, to solve its own necessities
m3	TSO subscription tool	This tool is necessary for the management of the subscription orders (limit that sets the amount of MW allowed to be drawn from TSO at each connection point)

For each functionality, the BUCs related to such functionality are specified, as well as the tools in which the functionality is considered.

Table 45: Identified functionalities of the Swedish demonstration campaign

ID	Functionality	Brief description	BUC(s)	Related tools (s)
1	Prequalification	Market operator receives information of prequalified resources	SE-1a, SE-3	m1, m2

2	Temporary subscription (vision, today done by flexibility tool)	The market platform asks for temporary subscription for the regional DSO from the TSO	SE-1a, SE-3	m1, m3
3	Flexibility bid forwarded	Bids not used by the DSO are made available to the TSO	SE-1a, SE-3	m1
4	Data exchange with other tools and actors	Market platform MUST be able to exchange data with other tools, systems or actors, such as DSO flexibility tool, DSO data hub, FSPs	SE-1a, SE-3	m1, m2, m3
5	Data exchange between the market platform tools	The individual tools that make up the market platform (today DSO market operation, TSO mFRR market) must be able to exchange data with each other	SE-1a, SE-3	m1, m2, m3
6	Market clearing for balancing	Market Operator clears the market considering the received bids	SE-3	m1, m2, m3
7	Market clearing for congestion management	Market Operator clears the market considering the received bids	SE-1a	m1, m2, m3
8	Settlement process (vision, today done partly manually)	Market operator settles process to FSPs	SE-1a, SE-3	m1, m2
9	Flexibility bid filtering according to market model, prequalification and bid format	The market platform validates whether the bids sent by FSPs can be used to solve SOs needs according to prequalification process, market model considered and defined bid format. It also checks for temporary limits on balancing bids	SE-1a, SE-3	m1, m3

Next tables, from Table 46 and Table 48, show the requirements related to each of the identified tools. In addition to the description of the requirement and the BUCs related to such requirement, the priority of the requirements is indicated. This priority emphasises the importance of successfully implementing the requirement. A numerical scale is used, from 1 (unimportant) to 5 (critical).

Table 46: Requirements of the "DSO market operation tool" of the Swedish demonstration campaign

ID	Description	Type	Priority	BUC
1	The tool MUST collect and store the bids from the FSPs (D-A & I-D)	Functional & data	5	SE-1a, SE-3
2	The tool MUST collect and store the ***orders*** from the DSO (D-A & I-D)	Functional & data	5	SE-1a, SE-3
3	The tool MUST supply recommendation of clearing volume according to merit order	Functional & data	5	SE-1a, SE-3
4	The tool MUST clear the market in accordance with the market design specifications (D-A & I-D)	Functional & data	5	SE-1a, SE-3
5	The tool MUST store all the input and clearing results	Functional & data	5	SE-1a, SE-3
6	The tool MUST send the DSO orders for the D-A & I-D to the FSP	Functional & data	5	SE-1a, SE-3
7	The tool MUST communicate the complete D-A & I-D clearing results to the DSO	Functional & data	5	SE-1a, SE-3
8	The tool MUST communicate the FSP bid clearing results (D-A & I-D) to the FSPs	Functional & data	5	SE-1a, SE-3
9	The tool SHOULD collect the baseline from the FSPs	Functional & data	4	SE-1a, SE-3
10	The tool SHOULD run based on a predefined schedule (e.g. every day at 09:30 and 10:00 for the D-A market).	Functional & data	4	SE-1a, SE-3

11	The tool SHOULD run as a continuous market (e.g. from D-A 15:00)	Functional & data	4	SE-1a, SE-3
12	The tool SHOULD be able to compute the settlement implication from the clearing results	Settlement	4	SE-1a, SE-3
13	The tool SHOULD identify the bids that can participate in the market (bid prequalification, etc.)	Functional & data	4	SE-1a, SE-3
14	The tool MUST store the prequalified resources (whenever required)	Functional & data	5	SE-1a, SE-3
15	The tool MUST collect and store temporary subscriptions as bids	Functional & data	5	SE-1a, SE-3
16	The tool MUST be able to transfer unused bids to TSO markets	Functional & data	5	SE-1a, SE-3
17	The tool MUST be able to receive the TSO clearing results	Functional & data	5	SE-1a, SE-3
18	The tool MUST be able to transfer clearing results from TSO markets to FSPs	Functional & data	5	SE-1a, SE-3

Table 47: Requirements of the “TSO market operation tool” of the Swedish demonstration campaign

ID	Description	Type	Priority	BUC
1	The tool MUST collect and store the unused bids from the DSO market operation	Functional & data	5	SE-1a, SE-3
2	The tool MUST make sure that the bids contain all information required in accordance with the current instruction (Ediel); such as volume, price, activation time, regulation object, bidding zone and time period for delivery.	Functional & data	5	SE-1a, SE-3
3	Before sending the bids, the tool MUST make sure that the bid meets the minimum bid size requirement (1 MW) and that the bid volume is rounded down to the nearest integer.	Functional & data	5	SE-1a, SE-3
4	Before sending the bids, the tool MUST make sure that all upward regulation bids have a higher price than the Spot price for the delivery hour.	Functional & data	5	SE-1a, SE-3
5	Before sending the bids, the tool SHOULD make sure that the bid price is not higher than the maximum price (currently 5 000 EUR/MW for upward bids), otherwise the bid will be rejected by the TSO market operation tool.	Functional & data	4	SE-1a, SE-3
6	The tool MUST clear the market in accordance with the result given by the TSO operation tool.	Functional & data	5	SE-1a, SE-3
7	The tool MUST store all the clearing results	Functional & data	5	SE-1a, SE-3
8	The tool MUST communicate the FSP bids clearing results to the DSO market operation tool	Functional & data	5	SE-1a, SE-3
9	The tool SHOULD run based on a predefined timing	Functional & data	4	SE-1a, SE-3
10	The tool SHOULD be able to compute the settlement implication from the clearing results	Settlement	4	SE-1a, SE-3
11	The tool SHOULD identify the bids that can participate in the market (bid prequalification)	Functional & data	4	SE-1a, SE-3
12	The tool MUST collect and store the prequalified resources (whenever required)	Functional & data	5	SE-1a, SE-3

Table 48: Requirements of the “TSO subscription tool” of the Swedish demonstration campaign

ID	Description	Type	Priority	BUC
1	The tool MUST collect and store TSO subscription orders	Functional & data	5	SE-1a, SE-3

2	The tool MUST store and show all results of subscription orders	Functional & data	5	SE-1a, SE-3
3	The tool MUST communicate all results of subscription orders	Functional & data	5	SE-1a, SE-3

8.3. Greek demonstrator

The market tools identified in the Greek demonstrator are detailed in Table 49, while their related functionalities and their requirements are specified in Table 50 and Table 51 - Table 53 respectively.

Table 49: Identified tools of the Greek demonstration campaign

ID	Tool	Brief description
m1	DSO market operation tool	It allows the operation, clearing and settlement of the local markets operated by the DSO. Once its needs are covered, the DSO transfers flexibility bids to the central market at TSO level
m2	TSO multi-level market operation tool	This tool is necessary for the acquisition of flexibility by the TSO, who has access to flexibility provided by DER, to solve its own necessities
m3	TSO fragmented market operation tool	This tool is necessary for the acquisition of flexibility by the TSO, who has no access to flexibility provided by DER, to solve its own necessities

For each functionality, the BUCs related to such functionality are specified, as well as the tools in which the functionality is considered.

Table 50: Identified functionalities of the Greek demonstration campaign

ID	Functionality	Brief description	BUC(s)	Related tools (s)
1	Prequalification	Market operator receives information of prequalified resources	GR-1a, GR-1b, GR-2a, GR-2b	m1, m2, m3
2	Flexibility bid filtering according to market model, prequalification and bid format	The market platform validates whether the bids sent by FSPs can be used to solve SOs needs according to prequalification process, market model considered and defined bid format. It also checks for temporary limits on balancing bids	GR-1a, GR-1b, GR-2a, GR-2b	m1, m2, m3
3	Data exchange with other tools and actors	Market platform MUST be able to exchange data with other tools, systems or actors, such as aggregator platform, DSO/TSO systems, FSPs, etc	GR-1a, GR-1b, GR-2a, GR-2b	m1, m2, m3
4	Data exchange between the market platform tools	The individual tools that make up the market platform (e.g. DSO market operation and TSO multi-level operation tools) must be able to exchange data with each other	GR-1a, GR-1b, GR-2a, GR-2b	m1, m2, m3
5	Market clearing for voltage control	Market Operator clears the market considering the received bids (active or reactive)	GR-1a, GR-1b	m1, m2, m3
6	Market clearing for congestion management	Market Operator clears the market considering the received bids (active or reactive)	GR-2a, GR-2b	m1, m2, m3

7	Settlement process	Market operator settles process to FSPs	GR-1a, GR-1b, GR-2a, GR-2b	m1, m2, m3

Next tables, from Table 51 to Table 53, show the requirements related to each of the identified tools. In addition to the description of the requirement and the BUCs related to such requirement, the priority of the requirements is indicated. This priority emphasises the importance of successfully implementing the requirement. A numerical scale is used, from 1 (unimportant) to 5 (critical).

Table 51: Requirements of the "DSO market operation tool" of the Greek demonstration campaign

ID	Description	Type	Priority	BUC
1	The tool MUST collect the bids of the FSPs connected to distribution system from the ESB platform (D-A & I-D)	Functional & data	5	GR-1a, GR-1b, GR-2a, GR-2b
2	The tool MUST collect the reserve requirement (D-A & I-D)	Functional & data	5	GR-1a, GR-1b, GR-2a, GR-2b
3	The tool MUST clear the market based on the market design (D-A & I-D)	Functional & data	5	GR-1a, GR-1b, GR-2a, GR-2b
4	The tool MUST send the accepted bids to the ESB (D-A & I-D)	Functional & data	5	GR-1a, GR-1b, GR-2a, GR-2b
5	The tool MUST collect the network model (R-T)	Functional & data	5	GR-1a, GR-1b, GR-2a, GR-2b
6	The tool MUST collect the forecast (R-T)	Functional & data	5	GR-1a, GR-1b, GR-2a, GR-2b
7	The tool MUST collect the already reserved capacity (R-T) from D-A & I-D	Functional & data	5	GR-1a, GR-1b, GR-2a, GR-2b
8	The tool MUST clear the market based on the market design (R-T)	Functional & data	5	GR-1a, GR-1b, GR-2a, GR-2b
9	The tool SHOULD run based on a predefined schedule (D-A, I-D & R-T)	Functional & data	4	GR-1a, GR-1b, GR-2a, GR-2b
10	The tool SHOULD clear the market within a predefined time window (D-A, I-D & R-T)	Functional & data	4	GR-1a, GR-1b, GR-2a, GR-2b
11	The tool SHOULD communicate the DSO the clearing results	Functional & data	4	GR-1a, GR-1b, GR-2a, GR-2b
12	The market algorithm MUST be robust	Functional & data	5	GR-1a, GR-1b, GR-2a, GR-2b
13	The market algorithm MUST clear the market in a transparent and non-discriminatory manner	Functional & data	5	GR-1a, GR-1b, GR-2a, GR-2b

Table 52: Requirements of the "TSO multi-level market operation tool" of the Greek demonstration campaign

ID	Description	Type	Priority	BUC
1	The tool MUST collect the bids of the FSPs connected to the transmission and distribution system from the ESB platform	Functional & data	5	GR-1a, GR-2a
2	The tool MUST collect the network model	Functional & data	5	GR-1a, GR-2a
3	The tool MUST collect the forecast	Functional & data	5	GR-1a, GR-2a
4	The tool MUST collect the already activated local bids	Functional & data	5	GR-1a, GR-2a
5	The tool MUST clear the market based on the market design	Functional & data	5	GR-1a, GR-2a
6	The tool SHOULD run based on a predefined schedule	Functional & data	4	GR-1a, GR-2a

7	The tool SHOULD clear the market within a predefined time window	Functional & data	4	GR-1a, GR-2a
8	The tool SHOULD communicate the DSO the clearing results	Functional & data	4	GR-1a, GR-2a
9	The tool SHOULD communicate the TSO the clearing results	Functional & data	4	GR-1a, GR-2a
10	The tool MUST send the accepted bids to the ESB	Functional & data	5	GR-1a, GR-2a
11	The market algorithm MUST be robust	Functional & data	5	GR-1a, GR-2a
12	The market algorithm MUST clear the market in a transparent and non-discriminatory manner	Functional & data	5	GR-1a, GR-2a

Table 53: Requirements of the “TSO fragmented market operation tool” of the Greek demonstration campaign

ID	Description	Type	Priority	BUC
1	The tool MUST collect the bids of the FSPs connected to the transmission system from the ESB platform	Functional & data	5	GR-1b, GR-2b
2	The tool MUST collect the network model	Functional & data	5	GR-1b, GR-2b
3	The tool MUST collect the forecast	Functional & data	5	GR-1b, GR-2b
4	The tool MUST clear the market based on the market design	Functional & data	5	GR-1b, GR-2b
5	The tool SHOULD run based on a predefined schedule	Functional & data	4	GR-1b, GR-2b
6	The tool SHOULD clear the market within a predefined time window	Functional & data	4	GR-1b, GR-2b
7	The tool SHOULD communicate the TSO the clearing results	Functional & data	4	GR-1b, GR-2b
8	The tool MUST send the accepted bids to the ESB	Functional & data	5	GR-1b, GR-2b
9	The market algorithm MUST be robust	Functional & data	5	GR-1b, GR-2b
10	The market algorithm MUST clear the market in a transparent and non-discriminatory manner	Functional & data	5	GR-1b, GR-2b

9. Conclusion

This deliverable reports on CoordiNet task 2.1 “Local and central markets to procure energy services” which describes the main characteristics of the market design dimensions and principles, but also how those principles are used in practice for the different CoordiNet demonstration campaigns. A special emphasis is made on congestion management, baseline methodology and market-clearing functionalities, tools and requirements for each demonstrator in the project. This deliverable coordinates the procurement schemes for different products, considering the nature of the product and including the specification of technical requirements, the existing market platforms and regulatory framework. The overall system architecture has been defined for the different demonstration campaigns. This deliverable is linked with the specification tasks of the different demonstration campaigns: T3.2, T4.2 and T5.2.

This document gives an overview of energy market design by listing the different market services, coordination schemes, market products and market dimensions. A technical and mathematical notion was used to get a clear and unambiguous understanding of market design concepts.

Those abstract concepts have been matched to the practical design used in the demonstration of the CoordiNet project. Special attention is devoted to the congestion management in the different demonstrations. In particular, congestion management market ID cards are used to present a detailed view of the different mechanisms put in practice.

Using the information on congestion management, numerical analyses of the relationship between market design and congestion management are performed for each demo sites. Some possible improvements are listed as a conclusion. The main improvements highlighted are related to computing marginal price in Spain to be more efficient, to optimize the DSO flexibility access in Sweden to improve market efficiency, and the trade-off between coordination and market efficiency in Greece.

This document also contains a review of the different baseline methodologies with practical example from the United States, Belgium and Netherlands. An evaluation framework has been described in detail. This leads to some specific recommendations regarding the baseline methodology to use for each demonstration of the CoordiNet project.

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11. Appendix A - Spanish market design ID cards

11.1. ES-2 – Balancing

Market service
The main focus of BUC ES-2 is balancing services. To help to tackle this issue, we develop a central market. The objective is to reduce balancing costs (TSO perspective), while avoiding unforeseen congestion problems at the distribution level.

Market participants
Generators, mainly wind farms in Cadiz and Albacete and some small hydropower plants. In principle demand-side resources will not provide balancing. Nevertheless, this option is still being discussed.

Coordination scheme
The implemented coordination scheme is the **central market** models (cf. Deliverable D1.3 [12]).

Market Product
Two products for congestion management have been defined (in T1.3.) • **Frequency restoration reserves** with manual activation • **Replacement reserves**

Market timing
mFRR: Needs and bids are submitted at D-1. The needs for mFRR will be published by the TSO before 21:00 of D-1, and bids will be sent before 23:00 of D-1. Offers can be updated up to 25 minutes before real-time. The clearing of the market happens in the real-time, according to the need of the TSO. Once the market is cleared, units have up to 15 minutes to provide the services. This FAT may be changed to 12.5 minutes in the future. **RR:** In Spain, the only RR market to take place will be the European one. Therefore, the TSO will receive bids for this product and forward them to the European platform for clearing. As of today, the gate closure time for the submission of bids will be 60 minutes before activation. The activation period is 60 minutes. This however is expected to change to 30 minutes and finally 15 minutes. 40 minutes before activation the TSO is expected to send the bids to the European platform. The FAT is 30 min.

Market dimensions	
Trading Type	Portfolio trading. According to the current market procedures, physical units are aggregated into "programming units"
Auction Type	The market is defined by **closed gate auctions.**
Centralization level	As detailed in the BUC definition, this local market is **highly centralized.**
Market pricing	This market (mFRR) is defined by a **uniform pricing rule** (**pay-as-cleared**).

	Two prices are used, one for upward regulation, and another for downward regulation, based on the merit order lists for the two directions.
Bid types	**mFRR:** Biding is mandatory for all generating units, as well as pumping units that are prequalified and that are able to provide this service. Units should offer, for each hour, all the available capacity, both upwards and downwards (MW) and the associated price (€/MWh). **RR:** Bids are voluntary and can be simple or complex. Minimum bid size is 1MW.
Objective type	mFRR: Cost Minimization.
Network representation in the market	No network is considered when clearing the mFRR. In case of constraints created by the tertiary regulation, the congestion management market is used.

11.2. ES-3 – Voltage control

Note, this is still under discussion. Initial discussion of DSO and TSO is not implementable due to technical issues at the time of writing.

Market service
The main focus of BUC ES-4, the controlled islanding, is to operate part of the distribution network in an islanding mode during outages. The resources considered in this activity are energy storage and PV located in medium and low voltage grids. Two islanding products will be tested in the Spanish demo: - Programmed maintenance, the FSP will automatically control the frequency and the voltage according to the setpoints sent by the DSO. - In case of an outage, a command will be sent from the DSO for the formation of the preselected island and the FSP will form the island similarly to a black start.

Once this is done, the FSP will control the frequency and the voltage according to the setpoints sent by the DSO, in the same way as in programmed islands. The DSO has to be able to maintain technical parameters such as voltage and frequency in the electrical island within required limits. The DSO has to determine the maximum size of the island in advance which, in turn, may affect the TSO. A prequalification process will be carried out between the FSP and DSO. The pre-qualification process for this product is flexible. The minimum requirements are specified but others are left open. It is essential to guarantee a long-term commitment between the DSO and the FSP. Although specific products for this service are not defined yet, it is assumed that capacity would be procured long term ahead

Market participants [D3.1]
For the DSO local market, the actors are the following: - The DSO (i-DE) for the management of the market. The DSO, primary actor of this BUC, has to be able to maintain the technical parameters (frequency and voltage) within required limits. The DSO activates the DG to supply the consumers within the island. - The battery used in this BUC will be controlled directly by i-DE - The TSO (REE, Red Eléctrica de España) is almost passive in this BUC, only receives the market outputs and consider the effects on balancing. - Market operator (i-DE will be performing the role of market operator).

Coordination scheme
The implemented coordination scheme is the **local market model.** Only a local need is considered and there is local acquisition of flexibility to maintain the islands during certain events such as outages or planned maintenance. (cf. Deliverable D1.3 [12]). During the operation of the island, the services needed would be similar to the defined ones for balancing (BUC-ES 2) and voltage control (BUC-ES 3). Therefore, at the very least, balancing and voltage control would be necessary and the corresponding market mechanisms should be required. [section 3.5, D3.1].

In this specific case no market coordination is envisioned, although coordination would still be needed between the DSO and TSO to share information (cf. section 4.3 of Deliverable D1.5 [52]).

Market timing [section 4.6, D3.1]
It is assumed that capacity would be procured long term ahead. The most relevant timescales: - Long-term: Evaluation of the islanding needs. Prequalification process between DSO-FSPs. Long-term contract is necessary. - Day-ahead: In case of planned outages, the DSO communicates the local platform the needs for islanding operation for the following day. The power, energy and timeframe will be specified. The FSP will determine the available flexibility, and compute power, energy and duration bids. - 1 hour before real time: The DSO dispatches resources according to the price-quantity bids for both power and energy in order to ensure frequency and voltage in security limits in the electrical island. The DSO registers the islanding operation in the CoordiNet platform, which informs the TSO and FSPs. The FSPs execute the instructions from the DSO. - After the event takes place: The reconnection with the rest of the system has to be done by a 0-Voltage. The DSO will send the command to de-activate the island to the CoordiNet platform which informs the TSO and the FSP. The TSO receives the information of reconnection and, if needed, is ready to compensate the impact on balancing from the temporarily isolation of the island from the rest of the system. In the meantime, the FSP execute the instructions from the DSO to disconnect the island. - After real-time: After the islanding operation, the DSOs meter the energy delivered and all the energy withdrawn from consumers during the islanding operation and performs the settlement.

Market dimensions	
Trading Type	Aggregation is not allowed. The market will be asymmetric, as the DSO received flexibility bids first and then selects the most appropriate ones.

	Bilateral contract.
Auction Type	Closed gate auctions with independent horizons.
Centralization level	Local market centralized at local level.
Market pricing	Pay-as-bid for capacity.
Bid types	Divisible and indivisible bids are allowed. No symmetry required. Minimum duration of delivery period: 15 minutes. Minimum quantity: 0.1 MW and 0.025 MWh with minimum cos φ=0.9 Granularity: 1kW and 1kWh
Objective type	Minimizing activation cost
Network representation in the market	--

12. Appendix B – Swedish market design ID cards

12.1. SE-3 – Balancing

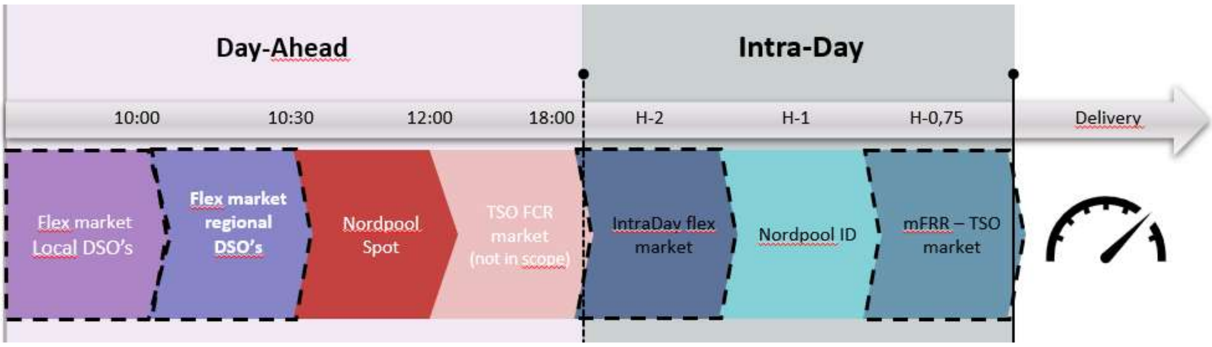
In this appendix, the market dimensions planned for the market of the BUC SE-3 are presented.

Market service
The main focus of BUC SE-3 is balancing on the transmission network level (products could also be used for congestion management between the electricity trading areas). It is the existing Nordic TSO mFRR market. Additional objectives of this market within the CoordiNet project is • To increase the liquidity of mFRR market (especially in SE4). To reduce the cost of the balancing. • To increase the business case for flexibility providers being able to sell their flexibility products to different markets in a feasible manner. • To increase the liquidity of CoordiNet local and regional market, to reduce the cost of congestion management.

Market participants
For the TSO mFRR, the actors are as follows: - The CoordiNet platform (run by regional DSOs, Vattenfall in Uppland and E.on in Skåne) is acting as an agent forwarding unused bids (that are prequalified for the mFRR-pilot following pilot prequalification criteria) from flexibility providers after the end of the intraday CoordiNet market to the national mFRR market. - The flexibility service providers - The TSO (Svenska Kraftnät) is the market operator responsible for the national mFRR market that is a part of Nordic mFRR market. - The flexibility providers have an agreement with the balancing responsible parties to participate on the mFRR-market

Coordination scheme

The implemented coordination scheme is the **multi-level market model** (cf. Deliverable D1.3 [12]), taking into consideration the first component of the market (which is the congestion management in SE 1a).



After the completion of the day-ahead (local and regional) and intraday flexibility market sessions, the unused bids over 1 MW will be transmitted to the TSO mFRR market (if the FSPs opt for this option).

Market timing
The market is defined by closed gate auctions, with a 1 single period hour horizon. Market frequency: The market will be used every hour on the day of operation. Gate closure time is 45 minutes before the hour of delivery, and the calling for flexibility (i.e., market clearing and communication of results) is communicated 15 min before delivery.

Market dimensions	
Trading Type	Asymmetric multilateral auction-based trading.
Auction Type	The market is defined by closed gate auctions.
Centralization level	This mFRR market is centralized at the national and Nordic TSOs levels.

Market pricing	Pay-as-cleared for balancing services.
Bid types	Hourly bids are considered with a 1 MW minimum size, where 1 MW/h bids are allowed.
Objective type	Minimizing the total cost of meeting the balancing (and congestion management) needs.
Network representation in the market	The locational information consists of the trade area in which the resource is located (i.e., SE1, SE2, SE3, and SE4)

13. Appendix C - Greek market design ID cards

13.1. GR-1a – 1b- Voltage control

Market service
The focus of BUCs GR-1a and GR-1b is on voltage control. The Greek demo focuses on steady state reactive and active power products for voltage control. The purpose of the market would be to ensure safe operation of the HV, MV and LV. electrical grid. Voltage is a localized property of the power system and it is essential that it does not exceed a certain level locally to maintain the health of grid assets.

Market participants
For voltage control market, the actors are as follows: • Market Operatror: It has not been decided yet whether the DSO or an independent actor will be the market operator. However, it is more likely the DSO to be the matker operator of the local market and the TSO the market operator of the TSO market • FSPs: Small diesel generators, HVAC and water pumps in Kefalonia. Battery Energy Storage System, Households and a small CHP in Mesogia. The FSPs are represented by an aggregator. • DSO: The system operator detects the voltage violations and asks for flexibility. • TSO: Depending on the coordination scheme that is applied the role of the TSO is different (see below).

Coordination scheme
The implemented coordination schemes are the **Multi-Level** and **Fragmented Market Models** (cf. Deliverable D1.3 [12]). In the Multi-Level Market Model, the FSPs that are connected to DS can provide flexibility to TS, after the DSO has assured that their activation will respect the DSO grid constraints.

Therefore, TSO can eliminate voltage violations using flexibility provided by the flexible resources connected to distribution and transmission system.

In the Fragmented Market Model, DSO and TSO can procure flexibility only from the

flexible resources connected to distribution and transmission system, respectively. The flexibility resources connected to DS can be used indirectly for the elimination of voltage violation in transmission system through the proper power exchange between them.

Market Product

Two products for voltage control have been defined (in T1.3.):

- **Steady state reactive** (capacity-based product).
- **Active power** (energy-based product)

Market timing

There are three types of market: day-ahead, intraday and real-time. The markets are either operated by the TSO or by the DSO. The DSO operates day-ahead, intraday and real-time (local) voltage control markets while the TSO operates only a real-time (global) voltage control market. The markets have the following timing characteristics:

- **Market frequency**.
    - Day-ahead: daily
    - Intraday: daily
    - near real-time: every 15 min
- **Market clearing time.**
    - Day-ahead: gates open at 16h D-1 and closes at 23h D-1 while results are published at 23:30 D-1.
    - Intraday: gates open at 5h D and closes at 08:30 D while results are published at 09:00 D.
    - near real-time: gates open at H-1h and closes at H-15min while results are published at H-5min.
- **Market horizon**.
    - Day-ahead: multiperiod market and will include 24 periods of 1h
    - Intraday: multiperiod with a granularity of 1h.
    - Real-time: single period of 15min.

Market dimensions	
Trading Type	
Auction Type	The market is defined by **closed gate auctions.** The auctions have **independent horizons**.
Centralization level	The local market is **centralized** (at a local level). However, in Mesogia and Near Real Time market, a centralized and a peer-to-peer approach will be implemented for the optimal activation of flexible resources.
Market pricing	This market is defined by a **uniform pricing rule** (**pay-as-cleared**)
Bid types	The market product (bid) is defined using the following format: • Member to identify the entity submitting the bid (aggregator or unit) • Broker Ref. to identify the unit ID in case an aggregator is submitting the bid. • Date of Delivery • Service to describe the service to be offered (Q or P) • Regulation (Upward or Downward) • Power to define the quantity of the bid in MW and WVar • Price to be defined • Location to define a connection within the grid from which the bidder will dispatch on activation.
Objective type	The goal when selecting the accepted bids are to **minimize offer cost**, respecting the system constraints
Network representation in the market	A graph is used to represent the physical network. A simplified network, instead of the whole network, might be used. The voltage limits of the lines should be taken into account. The power balance at each should be taken into account in order to find the optimal market solution.

14. Appendix D – Review of the baseline methodologies

In this report, five baseline methodologies are considered: Historical data approach, statistical sampling, maximum base load, meter before / meter after, and metering generator output. These methodologies are studied in the following sections, where their current practices found across selected countries are organized, conforming to Table 54.

Table 54: Baseline methodologies in selected countries

Baseline Methodology	Variants	Countries[18]
1. Historical data approach It is based on a demand resource's historical interval meter data, which may also include other variables such as weather and calendar data.	- Averaging methods (X of Y variants) - Regression - Comparable day - Rolling average method	- United States - Belgium
2. Statistical sampling This methodology uses statistical sampling to estimate the electricity usage of an aggregated Demand Resource where interval metering is not available on the entire population.		- United States
3. Maximum base load It is based solely on a Demand Resource's ability to maintain its electricity usage at or below a specified level during the activation of the service.	- Coincident - Non-coincident	- United States
4. Meter before/meter after Here, the electricity demand over a prescribed period of time prior to deployment is compared to similar readings during the sustained response period.		- United States - Belgium - Netherlands
5. Metering generator output In this methodology, the demand reduction value is based on the output of a generator located behind the demand resource's revenue meter.		- United States

14.1. Historical Data Approach

For energy-related products, a good baseline can be estimated using the historical consumption data of the FSPs, taken from a set of days that immediately precede the day of DR deployment. To measure and verify the contribution of FSP in day-ahead or real-time energy markets, the default methodology belongs to the historical data approach [39]. This methodology is the most prominent in DR programs today, and it is

[18] Some of the baseline methodologies presented for Belgium have been presented in design notes (such as for the cases of aFRR and FCR) and, hence, are currently discussed methodologies that may not be already implemented.

commonly known as baseline type-I in the NAESB (North American Energy Standards Board). It incorporates frequent granular measurement across similar days, resulting in a demand estimate that mimics the dynamic nature of a customer's demand curve over a 24-hour period [40].

The main characteristics of the historical data approach are; i) the baseline shape is the average load profile, ii) utilizes meter data from each individual site, iii) relies upon historical meter data from days immediately preceding the activation of the service, and iv) may use weather and calendar data to inform or adjust the baseline [43]. Moreover, this methodology includes variations, such as averaging methods, regression method, comparable day, and rolling average, which are described in the following subsubsections.

14.1.1. Averaging methods

The most widely used historical data approach are the averaging methods, which create baselines by averaging recent historical load data to build estimates of load for specific time intervals. Averaging methods are often called X of Y approaches, and they could be classified according to the relationship between X and Y as follows:

1. **High X of Y:** From an original pool of the last Z calendar days, the last Y working days are selected after applying the exclusion rules (see Exclusion rules below). The daily load of each of those Y days is calculated. The Y days are ranked according to their daily load from the highest to the lowest and, then, the highest X days are selected. The estimated load of the event day is the average of the load of the same hour of the days from those X days [54].

2. **Last Y days:** Like the previous methodology, last Y working days are selected from the pool of the last Z calendar days. However, the data of all Y days is used. The estimated load of the event day is the simple average of the load of the same hour of the day from those Y days [54].

3. **Middle X of Y:** In this case, some of the lowest and highest Y working days will be dropped and the retaining X middle consumption days will be used to calculate the baseline.

Besides, the selection of the number of days to use for an X of Y baseline is determined by the following considerations [43]:

1. **Look-back window:** The look-back window is the range of days prior to the event day that should be considered in identifying the Y days for an X of Y baseline. Today, many programs do not have a restriction on the look-back window; however, it is helpful to have a limit to avoid using data that is extremely outdated and thus likely not representative.

2. **Exclusion rules:** When calculating an X of Y baseline, certain days prior to the event day are excluded from the Y eligible days, generally because the load on those days is characteristically different from the load on the event day. The most common exclusion rule is to exclude days that are of a different type than the event day, where the type can include whether the event day is a working day vs. weekend or public holidays, as well as excluding previous events days, days of planned maintenance, and days of force majeure. In addition, some system operators allow BSPs to request exclusion days under certain defined settings.

3. **Time intervals:** Most programs capture frequent intervals of data. This captures greater detail around the load behavior of customers. In most analyses of baselines, hourly load data is used.

In addition, an adjustment to the X of Y calculated baseline is necessary to more accurately reflect load conditions of the event day. Factors used for adjustment rules may be based on, but are not limited to, temperature, humidity, calendar data, sunrise/sunset time and/or, event day operating conditions. According to [43], an adjustment is defined by the time frame that is used to make the adjustment and by the choices to use adjustments that are scalar or additive, capped or uncapped, symmetric or asymmetric, and weather-sensitive. A description of these concepts is presented below:

1. **Timing & Duration:** With the aim of better adjusting the baseline to the real conditions on the day of the activation of the service, a timing & duration adjustment is applied. This adjustment consists of measuring the actual load during a period prior to the event, comparing this measurement with the calculated baseline, and adding or subtracting the measured difference to the whole baseline to be applied during the activation of the service. In order to avoid that consumers vary their consumption once they know that the activation of the service will be applied, the period for adjustment finishes more than 1 hour before the event and, with a view to having similar conditions as in the event, the adjustment period does not start earlier than 4 hours before the event. Therefore, most baseline adjustments use a timeframe of 2-4 hours prior to the event.

2. **Scalar vs. Additive:** Adjustments can be calculated using a scalar or an additive factor. The scalar technique multiplies the provisional baseline load at each hour by a fixed amount or scalar, and the scalar multiplier is calculated as the ratio of the actual load to the provisional baseline load for some period prior to the curtailment. In contrast, the additive adjustment adds a fixed amount (kW) to the provisional baseline load in each hour. For instance, if load during the event day is 40 kW above the calculated baseline, then 40 kW is added to each interval in the actual event baseline.

3. **Capped vs. Uncapped:** In order to limit the magnitude of any adjustment, some programs use a cap, which establishes a limit on the magnitude of such adjustment.

4. **Symmetric vs. Asymmetric:** It is important to consider whether adjustments reflect demand conditions symmetrically (baseline adjusted up and down) or asymmetrically (baseline only adjusted up). The symmetric approach considers that day-of conditions can have a real impact on customer demand in both directions and therefore symmetric adjustments can maximize the accuracy of a baseline calculation. However, a symmetric adjustment can permit downward adjustments that could have damaging unintended consequences.

5. **Weather-sensitive:** This adjusts each baseline hourly value (kW) up or down by a weather adjustment factor. The weather adjustment factor is determined by a mathematical relationship derived through a regression analysis that considers the Demand Response Resource load and historical hourly consumption [45].

14.1.2. Regression method

Baseline calculation takes an extensive data set and determines the relationship among a number of different variables, such as weather, time of day and demand, among others [40]. Regression analysis may be the most accurate of baseline methodologies, because it takes into consideration more variables that influence load. Over the last years, numerous groups have compared the merits of regression baselines to High X of Y methods. However, regression baselines sacrifice simplicity for accuracy. They are complex to calculate and, as mentioned, they require multiple data such as load, weather, and day-type data [43].

14.1.3. Comparable day

The comparable day method allows an aggregator to find a day that is similar to the event day and use the load of that similar day as the baseline for the actual event day. This method still uses historical meter data but, unlike the averaging methods, it uses only data from one day rather than from multiple days. Another important characteristic of this method is that the selection of the baseline is made ex-post, after the activation.
Two challenges with the comparable day are, 1) it is not possible to know the baseline during the event, which could impede meeting curtailment goals, and 2) there are no objective criteria for selection of the day which makes it difficult to assess the appropriateness of a comparable day [43].

14.1.4. Rolling average method

The Rolling average baseline uses historical meter data from many days, but it gives greater weight to the most recent days. The baseline relies on a greater number of data points, which could improve accuracy for a customer who has similar load patterns and levels throughout the year. For customers whose energy usage fluctuates between seasons, however, the rolling average may not be the best method.

14.1.5. Examples of real implementation

14.1.5.1. United States

Programs throughout the United States (US) use a variety of baselines. Several of the reviewed reports analyze how system operators are currently using and applying the available baseline calculation methodologies. The proliferation of methodologies applied in the DR programs complicates the comparison of the solutions adopted by the various Independent System Operator (ISO)/Regional Transmission Organization (RTO) in the US. Specifically, in the case of PJM (Pennsylvania - New Jersey - Maryland - RTO) different default methodologies are used, depending on the relevant program and the type of product. Besides, alternative (ad hoc) methodologies can be agreed upon by PJM, the Curtailment Service Providers (CSP)[19], and the electricity distribution company involved. The ad-hoc methodology is mainly defined when the demand resource participating in the DR program has high variability in its load pattern [39].

Table 55 summarizes the main baselines regarding Historical Data Approach implemented in the United States, where the baseline variations and adjustments applied are specified. A description and examples of these baselines are presented below.

Table 55: Historical data approach - main baselines and adjustments in the United States[20]

[19] CSP: In the US, for entities that aggregate demand resources and participate on their behalf in wholesale markets

[20] In US the electrical services have different definitions as in Europe and, although they are not completely equivalent, the US services correspond to the following European ones: energy (US) refers to participation in the energy market providing electrical energy (active power), capacity (US) corresponds to firm capacity (i.e. adequacy service), reserve (US) corresponds to balancing capacity and regulation (US) to balancing energy.

Baseline Variant	Baseline	Service/ Product	Adjustment
X of Y Baselines	**10 in 10**, ISO: CAISO	Balancing Capacity, Energy	Scalar
	10 in 10, ISO: MISO	Firm Capacity, Energy	Weather-sensitive, or Scalar
	Mid 8-of-10, ISO: ERCOT	Firm Capacity	Scalar
	5-of-10, ISO: NYISO	Firm Capacity, Energy	Weather-sensitive, or Scalar
	4-of-5, ISO: PJM	Firm Capacity, Energy	Weather-sensitive, or Scalar
Weighted Average	**ISO-NE 90/10**, ISO: ISO-NE	Firm Capacity	Additive
Regression	**ERCOT-Regression**, ISO: ERCOT	Firm Capacity	Scalar
Comparable day	**ERCOT-Matching Day Pair**, ISO: ERCOT	Firm Capacity	Scalar

1. **"X of Y" Baselines:** It is the most common type of baseline, as the five US ISOs have an "X of Y" baseline available. Examples:

   - Baseline name: **10 in 10**, ISO: CAISO and MISO,
     Working day events: Hourly loads averaged over the ten most recent days preceding the event, excluding holidays, weekend days, and event days. Weekend or holiday events: Average hourly loads of the four most recent weekend or holiday days, excluding event days.
   - Baseline name: **Middle 8-of-10**, ISO: ERCOT,
     It is similar to the other "X of Y" baselines, except that the selection criterion for comparison days is to drop the highest and lowest kWh days out of the most recent ten. The working day baseline is calculated from the ten most recent working days, and the weekend day baseline is calculated from the ten most recent weekend days.
   - Baseline name: **5-of-10**, ISO: NYISO,
     It is another of the "highest X out of Y most recent days" type, with a selection criterion of the five highest kWh days out of the preceding ten non-holiday days (for working day events), or the two highest out of the preceding three (for the weekend or holiday events).
   - Baseline name: **4-of-5**, ISO: PJM,
     The PJM Economic Baseline consists of hourly loads averaged across the "highest X out of Y" most recent days, where X and Y are numbers that depend on day type. For working day events, the baseline consists of the average hourly loads of the four highest kWh days out of the five most recent working days preceding the event, excluding holidays, weekend days, and event days. For weekend or holiday events, the baseline consists of the average hourly loads of the two highest kWh days out of the three most recent weekend or holiday days, excluding event days.

2. **Weighted Average:** This baseline differs from the preceding ones in that it consists of a weighted average of the preceding day's baseline and the current day's actual metered load. The baseline is updated on every non-event working day. It is not calculated on weekends or holidays. On (working day) event days, the baseline is defined as the previous day's baseline. Example:

   - Baseline name: **ISO-NE 90/10**, ISO: ISO-NE.

3. **Regression:** This baseline is calculated using a regression model consisting of a daily energy equation, which has the customer's total daily kWh as the dependent variable, and 24 hourly energy fraction equations, in each of which is the dependent variable is the fraction of the daily load occurring in each hour of the day. Example:

   - Baseline name: **ERCOT-Regression**, ISO: ERCOT.

4. **Comparable day:** For instance, the ERCOT matching day-pair baseline consists of matching intervals for the entire day before and the day of the event up to one hour before the start of the event with the corresponding intervals for all day-pairs of the same day-pair type for the preceding year. Example:

   - Baseline name: **ERCOT-Matching Day Pair**, ISO: ERCOT.

Many of the previous baseline methodologies include a day-of adjustment, as described below:

- CAISO: This includes a symmetric scalar adjustment, unless otherwise requested by the Demand Response Participant (DRP) and approved by the CAISO. The scalar will be calculated by averaging the 4 hours prior to the event, excluding the hour immediately prior to the event start, and it is defined as a ratio of the average load for these three hours relative to the same 3-hour average of the Customer Baseline Load (CBL) calculation data set. The same scalar will be applied to each hour of the event. The scalar will be capped at both a 20% increase (load ratio = 1.2) and a 20% decrease (load ratio = 0.8) [55].
- ERCOT: ERCOT applies an event-day symmetric scalar adjustment to the baseline loads for any of the three default types defined in Table 55 (Middle 8 of 10, Regression, and Matching Day Pair). This adjustment is based on the Emergency Response Services (ERS) Load's actual load for the hours preceding the declaration of an Energy Emergency Alert, and the adjustment may be up or down. On the other hand, the control group methodology for the ERS weather-sensitive pilot does not include an adjustment.
- ISO-NE: For each day, ISO-NE calculates the real-time demand reduction amount of a real-time demand response asset or real-time emergency generation asset. The ISO will calculate an adjustment factor equal to the average difference (MW) between the asset's actual metered demand and its demand response baseline in the intervals during the two-hour period beginning 2.5 hours prior to the start of the first interruption interval in the operating day. The adjustment factor will be added to the demand response baseline in every interval of the day, which may increase or decrease the demand response baseline.
- MISO: The MISO baseline calculation includes the option of two day-of adjustments. The demand response resource delivering the energy product has an option at registration to select either a symmetric multiplicative adjustment or a weather-sensitive adjustment.
- NYISO: NYISO emergency and day-ahead CBL methods include an elective weather-sensitive CBL method that is essentially a multiplicative adjustment of the basic CBL method.
- PJM: PJM's standard CBL utilizes a symmetric additive adjustment, and there is also a weather-sensitive adjustment.

14.1.5.2. Belgium

The meter before / meter after method and the "High X of Y", along with a slightly modified version of High X of Y known as the "High X of Y*" method for Transfer of Energy (ToE), applications are the most commonly used methods (or proposed methods for future services) in Belgium. For ToE participation in the day-ahead and intraday markets, the High X of Y* methodology has been proposed [49].

Table 56 summarizes the main baselines regarding historical data approach implemented in Belgium. More details are described below.

Table 56: Historical Data Approach - Main Baselines in Belgium

Baseline Variation	Baseline	Service/Product

X of Y Baselines	High X of Y	mFRR
	High X of Y*	Wholesale flexibility (day-ahead/intraday DR)

mFRR

For mFRR, both baseline methodologies "High X of Y" and "Last QH" (referring to the last quarter of an hour) can be used by the BSP (Balancing Service Provider) [56], [57]. The BSP chooses which baseline methodology to use at each of its delivery points. These baseline methodologies guidelines also apply for mFRR provided through a ToE. A summary of the High X of Y method applied, as detailed in the mFRR terms and conditions in [57] is provided next.

For the selection of representative days, the days should be of the same type as the activation day, and no unforeseen events should have occurred during these days, which would have influenced the injection or offtake at the delivery point. Representative days can be of two categories (working day vs. weekend/public holidays) with the addition of a third optional category (which can be requested by the BSP), which consists of Mondays. A BSP can request the exclusion of certain representative days under certain conditions, including activation of balancing service at the delivery point during that day, force majeure, planned or unplanned maintenance, etc.

The reference days (the X days) are a subset of representative days and correspond to the X days during which the average active power offtake (or injection) during the 4 hours after the requested delivery time is highest (or lowest in case of injection).

The baseline value is the average of the X values measured at the delivery point during the X days and during the same quarter-hour as the requested activation quarter-hour.

The Y and X of each category of representative days for High X of Y for mFRR is as shown in Table 57.

Table 57: Representative and reference days in a High X of Y for mFRR in Belgium, [57]

Category of representative Days	X	Y
Working Days	4	5
Weekend / bank holiday	2	3
Mondays (only upon explicit request by the BSP)	2	3

Wholesale flexibility

For participation of demand-side flexibility services in the day-ahead and intraday markets using the ToE framework, the baseline methodology proposed is the High X of Y* method applied at each delivery point [49].

Similar to the mFRR case, the selection of representative days (the Y days) consists of choosing days that are of the same category as the activation day. These categories include working day, weekend and holidays, and Monday and 1st working day after a holiday (where the 3rd category is optional).

- A day in which the activation of the service took place may not be used as a representative day.

- The day before the activation of flexibility may also not be used as a representative day (to decrease the possibility of gaming).
- The FSP can request the exclusion of particular days from being considered as representative days subject to a set of conditions (e.g., force majeure, planned or unplanned maintenance, peak price day, etc.).

The selected X days are the days having the largest average consumption during the activation period and depend on the category of the activation. The values of X and Y for each category day are similar to the mFRR case.

The baseline value is the average of the X values (i.e. for each of the X reference days) of active power at the considered delivery point at the same quarter-hour as the quarter-hour at which the flexibility is activated during the activation day. This is typically the case for High X of Y baseline methodologies.

14.2. Statistical Sampling

Most baselines are created using historical meter data from the individual site of the customer. There are instances, where data from individual sites is not available, but data from a meter that aggregates or is representative of several sites is available instead. In these cases, the meter data can be used to create a baseline for a group of sites and, then, a method is used to allocate the load to specific sites. This baseline uses statistical sampling to estimate the electricity consumption of an aggregated demand resource where interval metering is not available on the entire population.

The statistical sampling methodology is more often used in residential DR programs, where it has been cost-prohibitive to install interval meters at every house. As the deployment of residential interval meters increases, however, the need for statistical sampling methods will likely decrease [43].

An as example of implementation, Table 58 summarizes the main baselines regarding statistical sampling implemented in the United States, where the services/products are specified according to [58].

Table 58: Statistical Sampling - Main Baselines in the United States

Baseline	Service/ Product
Type 2-Telemetry-Yes, ISO: ISO-NE	Energy
Type 2-Telemetry-No, ISO: ISO-NE	Energy, Firm Capacity
Manual-Sampled, ISO: MISO	Energy, Firm Capacity
10-in-10 Sampled, ISO: MISO	Energy, Firm Capacity
Base2(Small Customer Aggregations), ISO: NYISO	Energy, Firm Capacity
PJM-Base2, ISO: PJM	Energy, Firm Capacity

14.3. Maximum Base Load

Maximum Base Load (MBL) methods identify the maximum energy usage expected of each customer and, then, set a specific level of electricity usage that is equal to the maximum level, minus the committed capacity of the customer. The MBL is an example of a static baseline, because it remains at one level, as compared to the historical data approach method that generates a dynamic, changing profile of the load throughout the hours of the day. Note that with an MBL baseline, it is entirely possible for a customer to deliver flexibility by doing nothing at all, as long as its load is already at or below the “drop to” level [43].

Some of the main characteristics of this approach are: i) the baseline shape is static, ii) utilizes meter data from each individual site and from the system, and iii) relies upon historical meter data from the previous year [43].

The MBL baseline seems one of the simplest approaches, but, in contrast, it offers a poor accuracy (see subsection 7.2.5). However, MBL methods may be appropriate in several cases:

- A historical data approach method will not be able to accurately forecast load for a customer with volatile load patterns and, so, it is better to use an MBL method to set the baseline and expectations for curtailment.
- DR programs that are intended to ensure that load does not exceed levels used for planning and for which the load reductions in real-time are not so relevant. Historical data approach methods can guarantee that a certain amount of capacity is available in real-time, but MBL methods are more appropriate for ensuring the load stays at or below a set level.

Specifically, this approach is the most suitable one for capacity-related products [39].

14.3.1. Variants of Maximum Base Load

An MBL can be either coincident or non-coincident. A coincident baseline uses peak hours of the previous season that are chosen based on system load peaks. A non-coincident baseline also uses peak hours, but they are determined by individual load behavior and not by the system load. This means that the hours that contribute to the non-coincident baseline vary among customers. Based on analyses performed, it seems that the coincident baseline better predicts the collective load of enrolled resources during peak periods [43].

14.3.2. Example of real implementation

Table 59 summarizes the main baseline methodologies belonging to the MBL family implemented in the United States. The service/product information in this table was obtained from [59].

Table 59: Maximum Base Load - Main Baselines in the United States

Baseline	Service/ Product
Average Coincident Load (ACL), ISO: NYISO	Firm Capacity
Peak Load Contribution (PLC), ISO: PJM	Firm Capacity
ERCOT - Alternate, ISO: ERCOT	Firm Capacity
ISO-NE-MBL, ISO: ISO-NE	Balancing Capacity
MISO-Firm-Service-Level, ISO: MISO	Firm Capacity, Energy

This methodology is mainly used by the PJM and NYISO (New York Independent System Operator) in some of their programs. More details are presented below:

- Average Coincident Load (ACL) used by NYISO in the **Special Case Resources program**. This program pays retail electricity customers to provide their load reduction capability for a specified contract period. Based upon system condition forecasts, participants are notified to curtail this subscribed "capacity" to a firm power level [43].

- Peak Load Contribution (PLC), which is part of the Firm Service Level option in PJM's **Emergency Load Response Program (ELRP)**. This baseline is computed by averaging the customer's consumption recorded during the five highest peak hours of the five highest peak days on the whole PJM system during the previous summer (the so-called 'five coincidental peaks') [39].

Both methods identify the peak hours of the previous year (across a subset of hours) and then use the load on those hours to create an average maximum load for each customer. This maximum load becomes the baseline for all hours of the current summer. The main difference between the two methods is how peak hours are identified [43].

Next, an example of the application of this methodology (in PJM) provided by [43] is shown in Figure 42. In this example, the PLC is the average load of five peak hours during the summer months of the previous year. Only one hour per day can be used as a coincident peak hour in the PLC methodology. Based on the five highest summer peak hours from the table below, it can be set that the 2009 PLC would be 600 kW (average of the five hourly coincident values):

System Peak Rank	Hour	Date	TechBiz Load
1	4-5pm	June 09, 2008	590 kW
2	4-5pm	July 17, 2008	640 kW
3	4-5pm	July 18, 2008	615 kW
4	4-5pm	July 21, 2008	580 kW
5	4-5pm	June 10, 2008	575 kW

Figure 42: Example of MBL baseline methodology application in PJM, [43]

14.4. Meter Before / Meter After

In the Meter Before / Meter After (MBMA) methodology, the electricity consumption or demand over a prescribed period of time prior to deployment is compared to similar readings during the sustained response period. The baseline is generated using only actual load data from a time period immediately preceding an event [43].

Generally, an event for providing system services, whose duration is much shorter (from 10 minutes to 2 hours) is intended to reduce the load on the grid at that moment, for a short period of time, rather than to reduce a dynamic load profile likely to fluctuate over time. In the case of the system services provided by demand resources, the baseline can be better approximated by looking at the difference between the consumption level immediately before and immediately after the activation of the resources [39].

Examples of real implementation in different locations are presented in next subsections.

14.4.1. United States

Table 60 lists the main baselines regarding MBMA implemented in the United States. The service/product information in this table was obtained from [59].

Table 60: Meter before / meter after - Main Baselines in the United States

Baseline	Service/ Product
CAISO-MBMA, ISO: CAISO	Balancing Capacity
ERCOT-Reserves, ISO: ERCOT	Balancing Capacity
ERCOT-Regulation, ISO: ERCOT	Balancing Energy
MISO-MBMA-Single-Read, ISO: MISO	Firm Capacity, Balancing Capacity, Energy
ISO-MBMA-Interval-Reads, ISO: MISO	Balancing Energy
NYISO-MBMA, ISO: NYISO	Balancing Capacity, Balancing Energy
PJM-MBMA, ISO: PJM	Balancing Capacity, Balancing Energy, Energy

Generally, for frequency regulation and reserve, PJM adopts the MBMA methodology. In the case of regulation and reserves, both synchronized[21] and scheduled day-ahead, the services are remunerated in order to change the amount of power they withdraw from the grid at short-time notice (almost instantaneously for regulation, within 10 minutes for synchronized reserve and within 30 minutes for reserve scheduled day-ahead), for a shorter time duration (from seconds to a few hours) and with a higher degree of reliability. In this case, the system operator is interested in a precise change in the level of consumption, and the baseline used is generally the **meter before/meter after type**.

For example, in the case of a synchronized reserve, the baseline for a specific demand resource is set by the consumption level measured at the start of the event. This value is then compared to the consumption level measured ten minutes after the start of the event. The difference between these two values gives the demand reduction provided by that demand resource. For the day-ahead scheduling reserve, the contribution of demand response is verified similarly, but in this case the comparison is between the consumption level at the start of the event and 30 minutes after the start. Coherently, demand response providing a regulation service is verified by comparing consumption four seconds before the signal and consumption immediately after the signal [39], [40].

14.4.2. Belgium

Here, we note that some of the baseline methodologies presented next for Belgium have been discussed in design notes, such as for the cases of aFRR and FCR in [60] and [61] respectively. Hence, these methods might consist of proposed methodologies, which might differ from the currently implemented ones.

[21] Demand resources that have controls in place to automatically drop load in response to a signal from PJM within ten minutes (https://www.pjm.com/~/media/documents/manuals/m11.ashx)

A summary of the different MBMA baselines proposed in Belgium is illustrated in Table 61. More details are described below:

Table 61: Meter before / meter after - Main Baselines in Belgium

Baseline	Service/ Product
Meter before/meter after	FCR
Last QH	mFRR
Reference power with frequent update	aFRR

In Belgium, for FCR, a MBMA method is proposed, considering 20 seconds before the frequency deviation and 30 seconds after the time at which the frequency deviation is maximum [61]. The baseline is calculated as the difference between a) the average power (in MW) computed over a period of 20 seconds preceding the start of the frequency deviation and b) the maximum measured power value (in MW) during a period of 30 seconds succeeding the time instant at which the frequency deviation is at its maximal value.

The “Last QH” method, which uses a measurement from the delivery point 15 minutes before the activation time, is typically used for mFRR balancing services in Belgium [56], [57], [62]. For slow R3 control non-reserved service, the “Last QH” baseline methodology is used. In addition, the baseline values should not exceed 20% of the baseline value estimated using a “High X of Y” method. If that is the case, penalties will be applied.

According to Figure 43, the delivered aFRR power by a BSP at a delivery point at a certain time instant is the difference between the measured power at this delivery point and the baseline power [60]. The proposed baseline methodology is as follows:

- The aFRR baseline is determined by the BSP.
- Every 4 seconds, the BSP sends the baseline expected at its delivery point 1 minute afterward, i.e. the baseline for time t+60s is sent to the TSO at time t, and this process is repeated every 4 seconds. This baseline calculation should include any scheduled mFRR activation.
- The opportunity of gaming is considered low, as the updates are sent every 4 seconds without any knowledge by the BSP regarding the direction of the aFRR service which will be requested by the TSO.
- The accuracy of the baseline is validated by using what is known as “baseline tests”. In a baseline test, Elia (Belgian TSO) checks whether the baseline is equal to the measured power when no activation is performed.

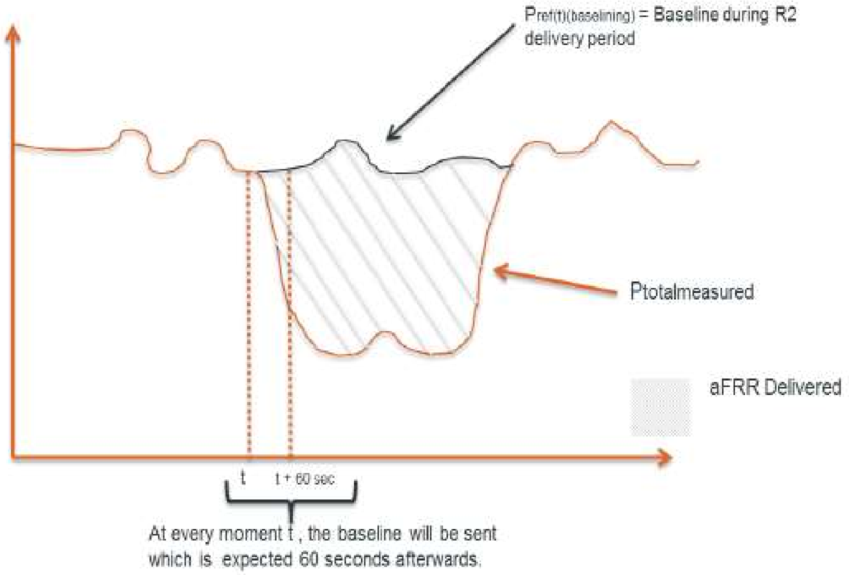


Figure 43: aFRR Baseline in Belgium, [60]

14.4.3. Netherlands

The information identified of the baseline methodologies used in the Netherlands for different services is presented next.

Manual Frequency Restoration Reserve directly activated (mFRRda): for mFRRda, the volume supplied by a BSP is volume = metered - reference value, where the reference value (i.e. the baseline) is defined as the amount of energy exchanged by the supplier at the delivery point during the five-minute period preceding the five-minute period in which the call is performed [63]. The total energy supplied by the BSP for an Imbalance Settlement Period (ISP) is the summation of the three volumes in each of the consecutive five minutes in this ISP [64].

Other baseline methods which are based on available schedules are also used in the Netherlands. For example, for ROD (Reserve Power Other Purposes) [64], which is used to decrease the risk of certain congestions and is based on a security analysis considering the N-1 criterion. The baseline level is the planned dispatch power level at the time of the activation.

Moreover, in the USEF project, a set of recommendations for baseline methodologies for different services offered by FSP was published as part of an analysis focusing on aggregator implementation models [65]. A summary of the recommendations for each service is provided next, where some methods fall within the scope of MBMA, while other methods rely on available schedules:

- The baseline for all services, except for the wholesale market, is recommended to be defined by the operator/purchaser of the flexibility (TSO for balancing services and DSO for congestion management), while for the wholesale market, the recommendation is for the baseline to be defined by the regulator.
- For FCR: the recommended baseline methodology is the MBMA method, relying on the most recent measured power level at the unit level, i.e. assuming a constant baseline.

- For aFRR: the baseline is recommended to be based on the rolling nomination of the aggregator or BSP for the following period, starting from the most recent power level measurement, and is to be provided on a unit level.
- For mFRR/tertiary control: the baseline methodology for tertiary control is recommended to be the same as that for aFRR, but in which the rolling nomination should cover the entire duration of the product (i.e. hours as compared to minutes in the aFRR case).
- For day-ahead trading: The baseline methodology for day-ahead trading is recommended to be based on the nomination of the aggregator or BSP during each ISP and presented on a unit level. Hence, this method relies on available schedules.
- For intraday trading: the baseline methodology for intraday trading is recommended to be similar to that for day-ahead, in the case the activation of the sold flexibility is within a long time period (i.e. 3 to 24 hours) from the time the flexibility is sold. In case the activation of the flexibility is within a short time from the time the flexibility is sold (i.e. < 3 hours), the recommended baseline methodology is to follow a similar methodology to tertiary control.

Besides, In the GOPACS (grid operators platform for congestion solutions) project [66], the product specification states that the delivered flexibility is based on the deviation from scheduled nominations at the connection point (if available) or on deviations from a defined “generation and load” schedule. Hence, these schedules constitute the baseline.

14.5. Metering Generator Output

This methodology is used when a generation asset is located behind the demand resources’ revenue meter, in which the demand reduction values are based on the output of the generation asset. This baseline is set as zero and measured against usage readings from behind-the-meter emergency back-up generators. This method is only applicable to facilitate on-site generation [43].

According to [46], if the use of behind-the-meter generation is permitted in the DR program, specific baseline methodologies may apply to the output of the behind-the-meter generation during the activation of the service or schedule. The applicable method is Metering Generator Output (MGO). However, depending on how the participant uses the generator absent an event, a baseline calculation may still be needed. The same baseline methodologies that are used for load participating as a resource may be applied to behind-the-meter generation. The value contributed to the program is measured as the difference between the metered generator output and the baseline generation for the event window. For wholesale DR, measuring only the metered generation does not capture the impact of the total demand response resource’s load on the wholesale power grid. As a result, MGO may be used in combination with another baseline methodology when the demand response resource reduces the load in addition to its behind-the-meter generation. Alternatively, metering at the retail delivery point may be used in lieu of separate metering of the behind-the-meter generator.

As an example or real implementation, Table 62 summarizes the main baselines regarding MGO implemented in the United States. The service/product information in this table was obtained from [59].

Table 62: Metering Generator Output - Main Baselines in the United States

Baseline	Service/ Product
ISO-NE-MGO, ISO: ISO-NE	Firm Capacity
MISO-MGO, ISO: MISO	Firm Capacity, Energy
NYISO-MGO, ISO: NYISO	Firm Capacity,

	Energy
PJM-MGO, ISO: PJM	Firm Capacity, Energy